APPENDIX
EXHIBITS (Pages 481-920)

Supreme Court of the United States

OCTOBER TERM, 1973

No. 72-402

UNITED STATES OF AMERICA,

Appellant

—v.—

GENERAL DYNAMICS CORPORATION, THE UNITED ELECTRIC COAL COMPANIES, and FREEMAN COAL MINING CORPORATION

ON APPEAL FROM THE UNITED STATES DISTRICT COURT FOR THE NORTHERN DISTRICT OF ILLINOIS

JURISDICTIONAL STATEMENT FILED SEPTEMBER 8, 1972
PROBABLE JURISDICTION NOTED DECEMBER 11, 1972

Supreme Court of the United States

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DEFENDANT'S EXHIBIT NO. 56

ANALYSIS OF SALES TO ELECTRIC UTILITIES OF COAL PRODUCED IN FULTON-PEORIA FREIGHT RATE DISTRICT

1. Utility Facilities Located in Fulton-Peoria Sales Area

Company	Facility	City	County	State
Illinois	Havana	Havana	Mason	Illinois
	Hennepin	Hennepin	Putnam	Illinois
CILCO	Edwards	Bartonville	Peoria	Illinois
	Liberty	Peoria	Peoria	Illinois
	Wallace	E. Peoria	Tazewell	Illinois
CIPS	Meredosia	Meredosia	Morgan	Illinois

2. Coal Consumption by Utility Facilities Located in Fulton-Peoria Sales Area

		Tons Consumed (000)		% of Total Consumption
Fulton-Peoria Production Consumed by Utilities in Sales Area		1984		80%
Consumption of Coal Produced in Other Frieght Rate Districts in Mining Districts 9, 10 & 11 1/				
Belleville	493		20%	
West Kentucky	1	494	*%	20%
TOTAL CONSUMPTION BY UTILITIES IN SALES AREA		2478		100%

3. Fulton-Peoria Production Sold to Utilities

	Tons Produced (000)	% of Total Production
Sold to Utilities in Sales Area	1984	34%
Sold to Commonwealth Edison	3794	65%
Sold to Other Utilities	28	1%
TOTAL PRODUCTION SOLD TO UTILITIES BY MINES IN FULTON-PEORIA FRT. DIST.	5806	100%

Source: Government Questionnaire

1/ Excludes shipment of 92,000 tons of dust from Crown Mine in Springfield District to Meredosia facility of CIPS. See CIPS Form 150 (Meredosia), Subpoena Questionnaire.

Table G - 2F

ANALYSIS OF SALES TO NON-UTILITY FACILITIES OF COAL PRODUCED IN THE FULTON-PEORIA FREIGHT RATE DISTRICT

1. Destinations in Fulton-Peoria Sales Area

City	County	State
Abingdon	Knox	Illinois
Aledo	Mercer	Illinois
Alexis	Warren	Illinois
Altona	Knox	Illinois
Atkinson	Henry	Illinois
Bartonville	Peoria	Illinois
Beardstown	Cass	Illinois
Bishop Hill	Henry	Illinois
Bushnell	McDonough	Illinois
Cambridge	Henry	Illinois
Canton	Fulton	Illinois
Cedar Point	LaSalle	Illinois
Chillicothe	Peoria	Illinois
Colchester	McDonough	Illinois
Cuba	Fulton	Illinois
Dixon	Lee	Illinois
E. Moline	Rock Island	Illinois
E. Peoria	Peoria	Illinois
Edelstein	Peoria	Illinois
Edwards	Peoria	Illinois
Elmwood	Peoria	Illinois
Erie	Whitesdie	Illinois
Fairview	Fulton	Illinois
Farmington	Fulton	Illinois
Galesburg	Knox	Illinois
Galva	Henry	Illinois
Geneseo	Henry	Illinois
Gilchrist	Mercer	Illinois
Garden Plain	Whiteside	Illinois
Kewanee	Henry	Illinois
Knoxville	Knox	Illinois
Lacon	Marshall	Illinois
Lafayette	Stark	Illinois
LaSalle	LaSalle	Illinois
Laura	Peoria	Illinois
Lewistown	Fulton	Illinois
Liverpool	Fulton	Illinois
Lyndon	Whiteside	Illinois

Table G - 2F
Cont'd

City	County	State
Macomb	McDonough	Illinois
Manlius	Bureau	Illinois
Mapleton	Peoria	Illinois
Marseilles	LaSalle	Illinois
Mendota	LaSalle	Illinois
Metamora	Rock Island	Illinois
Milan	Rock Island	Illinois
Moline	Rock Island	Illinois
Monica	Peoria	Illinois
Monmouth	Warren	Illinois
Montgomery	Kane	Illinois
Morton	Tazewell	Illinois
Mossville	Peoria	Illinois
Mt. Sterling	Brown	Illinois
Normandy	Bureau	Illinois
Norris	Fulton	Illinois
Oglesby	LaSalle	Illinois
Osco	Henry	Illinois
Ottawa	LaSalle	Illinois
Pekin	Tazewell	Illinois
Peoria	Peoria	Illinois
Peoria Heights	Peoria	Illinois
Peru	LaSalle	Illinois
Port Byron	Rock Island	Illinois
Princeton	Bureau	Illinois
Princeville	Peoria	Illinois
Prophetstown	Whiteside	Illinois
Rapatee	Knox	Illinois
Rock Falls	Whiteside	Illinois
Rock Island	Rock Island	Illinois
Rushville	Schuyler	Illinois
St. David	Fulton	Illinois
Seneca	LaSalle	Illinois
S. Pekin	Tazewell	Illinois
Sparland	Marshall	Illinois
Sterling	Whiteside	Illinois
Stronghurst	Henderson	Illinois
Tiskilwa	Bureau	Illinois
Toulon	Stark	Illinois
Walnut	Bureau	Illinois
Warsaw	Hancock	Illinois
Washburn	Woodford	Illinois
Wenona	Marshall	Illinois
Williamsfield	Knox	Illinois
Woodhull	Henry	Illinois
Wyoming	Stark	Illinois

Table G - 2F
Cont'd

City	County	State
Bettendorf	Scott	Iowa
Buffalo	Scott	Iowa
Clinton	Clinton	Iowa
Davenport	Scott	Iowa
Muscatine	Muscatine	Iowa
Princeton	Cott	Iowa

2. Coal Consumption by Non-Utility Facilities Located in Fulton-Peoria Sales Area

		Tons Consumed (000)	% of Total Consumption
Fulton-Peoria Production Consumed by Non-Utilities in Sales Area		2371	81%
Consumption of Coal Produced in Other Freight Rate Districts in Mining Districts 9, 10 & 11			
Southern Illinois	251 1/		9%
Belleville	7		*%
Springfield	1		*%
West Kentucky	31		1%
Mineral-Atkinson	284	574	10%
TOTAL CONSUMPTION BY NON-UTILITIES IN SALES AREA		2945	100% 2/

Source: Government Questionnaire

1/ Includes 73,000 tons (3%) of low-sulphur coal (1.2%) from Freeman's Orient #3 Mine in the Southern Freight District to the Dixon plant of Medusa Portland Cement for equipment requiring coal having a maximum sulphur content of 1.2%. See Medusa Portland Cement Form 150, Subpoena Questionnaire and letter of August 15, 1968 from Thompson, Hine and Flory to Plaintiff.

2/ The apparent discrepancy between actual sum of the subtotals above and the total above is due to rounding. Each figure has been rounded to the nearest one percent.

Table G - 2F
Cont'd

3. Fulton-Peoria Production Sold to Non-Utilities

	Tons Produced (000)	% of Total Production
Sold to Non-Utilities in Sales Area	2371	64%
Sold to Greater Chicago Air Quality Control Region	1004	27%
Sold to Other Non-Utilities	336	9%
TOTAL PRODUCTION SOLD TO NON-UTILITIES FROM MINES IN FULTON-PEORIA FRT. DIST.	3711	100%

Source: Government Questionnaire

Table G - 3P

RECAPITULATION OF SALES OF COAL PRODUCED IN THE FULTON-PEORIA FREIGHT RATE DISTRICT

1. **Coal Consumption by All Facilities in Fulton Peoria Sales Area**

		Tons Consumed (000)		% of Total Consumption
Fulton-Peoria Production Consumed by All Facilities in Sales Area		4355		80%
Consumption of Coal Produced in Other Freight Rate Districts in Mining Districts 9, 10 & 11 1/				
Belleville	500		9%	
Southern Illinois	251		5%	
Springfield	1		*	
West Kentucky	32		1%	
Mineral-Atkinson	284	1068	5%	20%
TOTAL CONSUMPTION OF COAL BY FACILITIES IN SALES AREA		5432		100%

2. **Fulton-Peoria Production Sold to All Facilities**

	Tons Produced (000)	% of Total Production
Sold to Facilities in Sales Area	4355	46%
Sold to Commonwealth Edison	3794	40%
Sold to Chicago Air Quality Control Region	1004	11%
Sold to Other Facilities	364	4%
TOTAL	9517	100% 2/

Excludes shipment of 92,000 tons of dust from Crown Mine in Springfield District to Meredosia facility of CIPS.

Includes 73,000 tons (4%) of low-sulphur coal (1.2%) from Freeman's Orient #3 Mine in the Southern Freight District to the Dixon plant of Medusa Portland Cement for equipment requiring coal having a maximum sulphur content of 1.2%. See Medusa Portland Cement Form 150, Subpoena Questionnaire and letter of August 15, 1968 from Thompson, Hine and Flory to Plaintiff.

The apparent discrepancy between ac[illegible]l sum of the subtotals above and the total above is due to rounding. [illegible]ch figure has been rounded to the nearest one percent

Table G - 1s

ANALYSIS OF SALES TO ELECTRIC UTILITIES OF COAL PRODUCED IN SPRINGFIELD FREIGHT RATE DISTRICT

1. Utility Facilities Located in Springfield Sales Area

Company	Facility	County	State
CIPS	Coffeen	Montgomery	Illinois
SPRINGFIELD WL&P	Springfield	Sangamon	Illinois

2. Coal Consumption by Utility Facilities Located in Springfield Sales Area

	Tons Consumed (000)	% of Total Consumption
Springfield Production Consumed by Utilities in Sales Area	1406	100%
Consumption of Coal Produced in Other Freight Rate Districts in Mining Districts 9, 10 & 11	0	0%
TOTAL CONSUMPTION BY UTILITIES IN SALES AREA	1406	100%

3. Springfield Production Sold to Utilities1/

	Tons Produced (000)	% of Total Production
Sold to Utilities in Sales Area	1406	16%
Sold to Commonwealth Edison	7191	84%
Sold to Other Utilities	0	0%
TOTAL PRODUCTION SOLD TO UTILITIES BY MINES IN SPRINGFIELD FRT. DIST.	8597	100%

Source: Government Questionnaire

1/ Excludes 92,000 tons of dust shipped from the Crown Mine of Freeman to the Meredosia facility of CIPS. See CIPS Form 150 (Meredosia), Subpoena Questionnaire.

Table G - 2s

ANALYSIS OF SALES TO NON-UTILITY FACILITIES OF COAL PRODUCED IN THE SPRINGFIELD FREIGHT RATE DISTRICT

1. Destinations in the Springfield Sales Area

City	County	State
Carlinville	Macoupin	Illinois
Decatur	Macon	Illinois
Edinburg	Christian	Illinois
Hillsboro	Montgomery	Illinois
Irving	Montgomery	Illinois
Kincaid	Christian	Illinois
Mechanicsburg	Sangamon	Illinois
Morrisonville	Christian	Illinois
Nokomis	Montgomery	Illinois
Oconee	Shelby	Illinois
Pana	Christian	Illinois
Pawnee	Sangamon	Illinois
Ramsey	Fayette	Illinois
Riverton	Sangamon	Illinois
Springfield	Sangamon	Illinois
Witt	Montgomery	Illinois

Table G - 2s
Cont'd

2. Coal Consumption by Non-Utility Facilities Located in Springfield Sales Area

		Tons Consumed (000)		% of Total Consumption
Springfield Production Consumed by Non-Utilities in Sales Area		349	*	80%
Consumption of Coal Produced in Other Freight Rate Districts in Mining Districts 9, 10 & 11				
Southern	4		1%	
Murdock	63		14%	
Danville	12		3%	
Indiana	8		2%	
W. Kentucky	2	89	*%	20%
TOTAL CONSUMPTION BY NON-UTILITIES IN SALES AREA		438		100%

3. Springfield Production Sold to Non-Utilities

	Tons Produced (000)	% of Total Production
Sold to Non-Utilities in Sales Area	349	89%
Sold to Greater Chicago Air Quality Control Region	19	5%
Sold to Other Non-Utilities	24	6%
TOTAL PRODUCTION SOLD TO NON-UTILITIES FROM MINES IN SPRINGFIELD FRT. DIST.	392	100%

Source: Government Questionnaire

Table G-3S

RECAPITULATION OF SALES OF COAL PRODUCED IN THE SPRINGFIELD FREIGHT RATE DISTRICT

1. Coal Consumed by All Facilities in Springfield Sales Area

		Tons Consumed (000)		% of Total Consumption
Springfield Production Consumed by All Facilities in Sales Area		1755		95%
Consumption of Coal Produced in Other Freight Rate Districts in Mining Districts 9, 10 & 11				
Southern	4		*	
Murdock	63		3%	
Danville	12		1%	
Indiana	8		*	
West Kentucky	2	89	*	4%
TOTAL CONSUMPTION OF COAL BY FACILITIES IN SALES AREA		1844		100% 1/

2. Springfield Production Sold to All Facilities 2/

	Tons Produced (000)	% of Total Production
Sold to Facilities in Sales Area	1755	20%
Sold to Commonwealth Edison	7191	80%
Sold to Chicago Air Quality Control Region	19	*
Sold to Other Facilities	24	*
TOTAL	8989	100%

1/ The apparent discrepancy between actual sum of the subtotals above and the total above is due to rounding. Each figure has been rounded to the nearest one percent.

2/ Excludes 92,000 tons of dust shipped from the Crown Mine of Freeman to the Meredosia facility of CIPS. See CIPS Form 150 (Meredosia), Subpoena Questionnaire.

Source: Government Questionnaire

Table G - 1B

ANALYSIS OF SALES TO ELECTRIC UTILITIES OF COAL PRODUCED IN BELLEVILLE FREIGHT RATE DISTRICT

1. Utility Facilities Located in Belleville Sales Area

Company	Facility	City	County	State
Dairyland Power	Stoneman	Cassville	Clayton	Wisconsin
Dairyland Power	Alma	Alma	Wabasha	Wisconsin
Dairyland Power	Genoa	Genoa	Vernon	Wisconsin
Wisconsin P & L	Nelson Dewey	Cassville	Clayton	Wisconsin
Elk River Rural Co-operative	Elk River	Elk River	Sherburne	Minnesota
Northern Sts. Power	French Island	LaCrosse	LaCrosse	Wisconsin
Northern Sts. Power	Red Wing	Red Wing	Goodhue	Minnesota
Northern Sts. Power	Winona	Winona	Winona	Minnesota
Northern Sts. Power	King	Stillwater	Washington	Minnesota
Northern Sts. Power	High Bridge	St. Paul	Ramsey	Minnesota
Northern Sts. Power	Black Dog	Minneapolis	Ramsey	Minnesota
Northern Sts. Power	Riverside	Minneapolis	Ramsey	Minnesota
Interstate Power	Dubuque	Dubuque	Dubuque	Iowa
Interstate Power	Lansing	Lansing	Almakee	Iowa
Interstate Power	Kapp	Clinton	Muscatine	Iowa
Municipal Electric	Muscatine	Muscatine	Muscatine	Iowa
E. Iowa Light & Power	Montpelier	Montpelier	Muscatine	Iowa
Iowa-Ill. Gas & Elec.	Riverside	Bettendorf [Iowana]	Scott	Iowa
Ill. Power	Wood River	Wood River	Madison	Illinois
City of Highland	Highland	Highland	Madison	Illinois
Union Electric	Venice	Venice	Madison	Illinois
Uniom Electric	Cahokia	Cahokia	Sinclair	Illinois
Union Electric	Ashley	St. Louis	St. Louis	Missouri
Union Electric	Meramec	St. Louis	St. Louis	Missouri
Central Elec. Power Coop.	Chamois	Chamois	Callaway	Missouri

2. Coal Consumption by Utility Facilities Located in Belleville Sales Area

		Tons Consumed (000)		% of Total Consumption
Belleville Production Consumed by Utilities in Sales Area		7595		81%
Consumption of Coal Produced in Other Freight Rate Districts in Mining Districts 9, 10 & 11				
Southern[1/]	895		10%	20%
Fulton Peoria	4		*	
West Kentucky	453		5%	
Mineral-Atkinson	426	1778	5%	
TOTAL CONSUMPTION BY UTILITIES IN SALES AREA		9373		100%[2/]

Table G - 1B
(Cont'd)

3. Belleville Production Sold to Utilities

	Tons Produced (000)	% of Total Production
Sold to Utilities in Sales Area	7595	46%
Sold to Commonwealth Edison	6514	39%
Sold to Greater Chicago Air Quality Control Region	1279	8%
Sold to Other Utilities	1296	8%
TOTAL PRODUCTION SOLD TO UTILITIES BY MINES IN BELLEVILLE FREIGHT DISTRICT	16684	100%

1/ Excludes 1,171,337 tons of dust from the following mines in the Southern Freight District to the following utility facilities: Sahara to the Cahokia (59,000) and Venice (76,000) plants of Union Electric; Old Ben No. 9 to the Venice (49,000) and Meramec (319,000) plants of Union Electric; Orient No. 3 to the Venice (112,369) and Meramec (191,828) plants of Union Electric, the Wood River (181,132) plant of Illinois Power and the Alma (53,911) plant of Dairyland Power; Orient No. 5 to the Alma (29,097) plant of Dairyland Power. See corresponding Forms 150, Subpoena Questionnaire.

2/ The apparent discrepancy between actual sum of the subtotal above and the total above is due to the rounding. Each figure has been rounded to the nearest one percent.

Source: Government Questionnaire

ANALYSIS OF SALES TO NON-UTILITY FACILITIES OF COAL PRODUCED IN THE BELLEVILLE FREIGHT RATE DISTRICT

1. Destinations in Belleville Sales Area

City	County	State
Alton	Madison	Illinois
Belleview	Calhoun	Illinois
Belleville	St. Clair	Illinois
Chester	Randolph	Illinois
Collinsville	Madison	Illinois
E. Alton	Madison	Illinois
E. St. Louis	St. Clair	Illinois
Edwardsville	Madison	Illinois
Evansville	Randolph	Illinois
Freeburg	St. Clair	Illinois
Granite City	Madison	Illinois
Madison	Madison	Illinois
Marissa	St. Clair	Illinois
Mascoutah	St. Clair	Illinois
Millstadt	St. Clair	Illinois
Pinckneyville	Perry	Illinois
Prairie DuRocher	Randolph	Illinois
Roxanna	Madison	Illinois
Sand Cut	Madison	Illinois
Sauget	St. Clair	Illinois
Sparta	Randolph	Illinois
Staunton	Macoupin	Illinois
Steeleville	Randolph	Illinois
Swanwick	Perry	Illinois
Venice	Madison	Illinois
Willisville	Perry	Illinois
Wood River	Madison	Illinois
Berkeley	St. Louis	Missouri
Brentwood	St. Louis	Missouri
Clayton	St. Louis	Missouri
Crescent	St. Louis	Missouri
Hine	St. Louis	Missouri
Koch	St. Louis	Missouri
Prospect Hill	St. Louis	Missouri
St. Charles	St. Charles	Missouri
St. Louis	St. Louis	Missouri
Weldon	St. Charles	Missouri

(Cont'd)

2. Coal Consumption by Non-Utility Facilities Located in Belleville Sales Area

		Tons Consumed (000)		% of Total Consumption
Belleville Production Consumed by Non-Utilities in Sales Area		2027		94%
Consumption of Coal Produced in Other Freight Rate Districts in Mining Districts 9, 10 & 11				
Southern	107		5%	
Indiana	1		*	
West Kentucky	15	123	1%	6%
TOTAL CONSUMPTION BY NON-UTILITIES IN SALES AREA		2150		100%

3. Belleville Production Sold to Non-Utilities

	Tons Produced (000)	% of Total Production
Sold to Non-Utilities in Sales Area	2027	63%
Sold to Greater Chicago Air Quality Control Region	763	24%
Sold to Other Non-Utilities	409	13%
TOTAL PRODUCTION SOLD TO NON-UTILITIES FROM MINES IN BELLEVILLE FREIGHT DISTRICT	3199	100%

Source: Government Questionnaire

Table G - 3B

RECAPITULATION OF SALES OF
COAL PRODUCED IN THE BELLEVILLE
FREIGHT RATE DISTRICT

1. Coal Consumption by All Facilities in Belleville Sales Area

		Tons Consumed (000)	% of Total Consumption
Belleville Production Consumed by All Facilities in Sales Area		9622	84%
Consumption of Coal Produced in Other Freight Rate Districts in Mining Districts 9, 10 & 11			
Southern Illinois 1/	1002		9%
Fulton-Peoria	4		*
Mineral-Atkinson	426		4%
West Kentucky	468		4%
Indiana	1	1901	* 17%
TOTAL CONSUMPTION OF COAL BY FACILITIES IN SALES AREA		11523	100% 2/

2. Belleville Production Sold to All Facilities

	Tons Produced (000)	% of Total Production
Sold to Facilities in Sales Area	9622	48%
Sold to Commonwealth Edison	6514	33%
Sold to Chicago Air Quality Control Region	2042	10%
Sold to Other Facilities	1705	9%
TOTAL	19883	100% 2/

1/ Excludes 1,171,337 tons of dust from the following mines in the Southern Freight District to the following utility facilities: Sahara to the Cahokia (59,000) and Venice (76,000) plants of Union Electric; Old Ben No. 9 to the Venice (49,000) and Meramec (319,000) plants of Union Electric; Orient No. 3 to the Venice (112,369) and Meramec (191,828) plants of Union Electric, the Wood River (181,132) plant of Illinois Power and the Alma (53,911) plant of Dairyland Power; Orient No. 5 to the Alma (29,097) plant of Dairyland Power. See corresponding Forms 150, Subpoena Questionnaire.

2/ The apparent discrepancy between actual sum of the subtotal above and the total above is due to rounding. Each figure has been rounded to the nearest one percent.

Table G - 180

ANALYSIS OF SALES TO ELECTRIC UTILITIES OF COAL PRODUCED IN SOUTHERN (ILLINOIS) FREIGHT RATE DISTRICT

1. Utility Facilities Located in Southern Sales Area

Company	Facility	City	County	State
TVA	Shawnee	Paducah	McCracken	Kentucky
State of Wis.P.Plt	Waupun	Waupun	Fond du Lac	Wisconsin
Wisc. P & L	Edgewater	Sheboygan	Sheboygan	Wisconsin
Wisc. E. P.	Port Washington	Port Washington	Ozaukee	Wisconsin
Wisc. E. P.	Oak Creek	Oak Creek	Milwaukee	Wisconsin
Wisc. E. P.	Lakeside	St. Francis	Milwaukee	Wisconsin
Wisc. Pub. Serv.	Weston	Green Bay	Brown	Wisconsin
Wisc. Pub. Serv.	Pulliam	Rothschild	Marathon	Wisconsin
Lake Sup.Dist.Pwr.	Bayfront	Ashland	Ashland	Wisconsin
Marshfield E & W	Wildwood	Marshfield	Wood	Wisconsin
Menasha E & W	Menasha	Menasha	Winnebago	Wisconsin
Electric Energy	Joppa	Joppa	Massac	Illinois
CIPS	Grand Tower	Grand Tower	Jackson	Illinois
So.Ill.Pow.Coop.	Marion	Marion	Williamson	Illinois
Union Electric	Sioux	W. Alton	St. Charles	Missouri
N.E.Mo.E.Pwr.Coop.	South River	Palmyra	Marion	Missouri
Ia. E. L. & P.	Sutherland	Marshalltown	Marshall	Iowa
Ia. E. L. & P.	6th St. Station	Cedar Rapids[Crandic]	Linn	Iowa
Ia. E. L. & P.	Iowa Falls	Iowa Falls	Hardin	Iowa
Ia. - Ill. Gas	Iowa City	Iowa City	Johnson	Iowa
Ia. Public Serv.	Maynard	Waterloo	Black Hawk	Iowa
Munic. P&L Dept.		Grundy Center	Grundy	Iowa
Spencer Mun.Util.		Spencer	Clay	Iowa
Munic.Light Plt.		Sibley	Osceola	Iowa
Cedar Falls Util.		Cedar Falls	Black Hawk	Iowa
Iowa So. Util.	Bridgeport	Eddyville	Wapello	Iowa
Webster City L&P		Webster City	Hamilton	Iowa
Austin Utilities		Austin	Mower	Minnesota
Interstate Power		Sherburn	Martin	Minnesota
Board of L & P	City of Marquette	Marquette	Marquette	Michigan

2. Coal Consumption by Utility Facilities Located in Southern Sales Area

	Tons Consumed (000)		% of Total Consumption	
Southern Production Consumed by Utilities in Sales Area		7232		48%
Consumption of Coal Produced in Other Freight Rate Districts in Mining Districts 9, 10 & 11				
Belleville1/	619		4%	
Mineral-Atkinson	530		4%	
Murdock	9[illegible]		1%	
West Kentucky2/	633[illegible]		42%	
Indiana	32[illegible]	7899	2%	53%
TOTAL CONSUMPTION BY UTILITIES IN SALES AREA		15131		100%3/

Table G - 150
(Cont'd)

3. Southern Production Sold to Utilities

	Tons Produced (000)	% of Total Production
Sold to Utilities in Sales Area	7232	80%
Sold to Commonwealth Edison	120	1%
Sold to Other Utilities	1753	19%
TOTAL PRODUCTION SOLD TO UTILITIES BY MINES IN SOUTHERN FREIGHT DISTRICT	9105	100%

1/ Includes (1) 213,000 tons (3%) from the Fidelity Mine of United Electric to the Shawnee plant of TVA in Paducah, Kentucky, shipped under a Freeman contract. In response to Form 150 of the Subpoena Questionnaire, TVA received no other Belleville Freight District coal. In response to the Government questionnaire, no other Belleville producer reported sales to TVA. See also, Nugent Dep. Tr. p. 235. (2) Also includes 132,000 tons (2%) from the Fidelity mine of United Electric to the Weston plant of Wisconsin Power & Light in Green Bay, Wisconsin shipped under a Freeman contract. See also Morrison Dep. Tr. p. 18.

2/ Included within West Kentucky total is a one-third allocation [185,805.90] of the 557,417.70 tons shipped in 1967 from Tab-Badgett Lakeview Mine to "T.V.A.'s Widow Creek, Gallatin, and Shawnee Plants." In the absence of any evidence to the contrary, one-third of the aggregate tonnage has been attributed as the portion shipped to the Shawnee Plant in the Southern Utility Sales Area.

3/ The apparent discrepancy between actual sum of the subtotals above and the total above is due to rounding. Each figure has been rounded to the nearest one percent.

4/ Excludes 1,171,337 tons of dust from various mines to Belleville sales area utilities. See Footnote 2, Table G-1B.

Source: Government Questionnaire.

Table G - 2SO

ANALYSIS OF SALES TO NON-UTILITY FACILITIES OF COAL PRODUCED IN THE SOUTHERN (ILLINOIS) FREIGHT RATE DISTRICT[1/]

1. Destinations in Southern Sales Area

City	County	State
Carbondale	Jackson	Illinois
Grand Tower	Jackson	Illinois
Harrisburg	Saline	Illinois
Herrin	Williamson	Illinois
Joppa	Massac	Illinois
Marion	Williamson	Illinois
Metropolis	Massac	Illinois
Ordill	Williamson	Illinois
Pulley's Mill	Williamson	Illinois
Rosiclare	Hardin	Illinois
Shawneetown	Gallatin	Illinois
Stonefort	Saline	Illinois
Villa Ridge	Pulaski	Illinois
Alladin	Black Hawk	Iowa
Albert City	Buena Vista	Iowa
Albia	Monroe	Iowa
Ames	Story	Iowa
Bloomfield	Davis	Iowa
Cedar Falls	Black Hawk	Iowa
Cedar Rapids [Crandic]	Linn	Iowa
Coin	Page	Iowa
Des Moines	Polk	Iowa
Eddyville	Wapello	Iowa
Fairfield	Jefferson	Iowa
Fort Dodge	Webster	Iowa
George	Lyon	Iowa
Iowa City	Johnson	Iowa
Keosauqua	Van Buren	Iowa
Mason City	Cerro Gordo	Iowa
Montezuma	Poweshiek	Iowa
Monticello	Jones	Iowa
Newton	Jasper	Iowa
North English	Iowa	Iowa
Oakdale	Johnson	Iowa
Ocheyedan	Osceola	Iowa
Oelwein	Fayette	Iowa
Olin	Jones	Iowa
Oskaloosa	Mahaska	Iowa
Ottumwa	Wapello	Iowa
Sigourney	Keokuk	Iowa
Stanwood	Cedar	Iowa
Stockport	Van Buren	Iowa
Tama	Tama	

Table G - 2SO
(Cont'd)

City	County	State
Tipton	Cedar	Iowa
Vinton	Benton	Iowa
Washington	Washington	Iowa
Waterloo	Black Hawk	Iowa
W. Des Moines	Polk	Iowa
Adell	Sheyboygan	Wisconsin
Appleton	Outagamie	Wisconsin
Ashland	Ashland	Wisconsin
Biron	Wood	Wisconsin
Cudahy	Milwaukee	Wisconsin
Eden	Fond du Lac	Wisconsin
Green Bay	Brown	Wisconsin
Kaukauna	Outagamie	Wisconsin
Kenosha	Kenosha	Wisconsin
Kimberley	Outagamie	Wisconsin
Knowles	Dodge	Wisconsin
Manitowoc	Manitowoc	Wisconsin
Marinette	Marinette	Wisconsin
Marshfield	Wood	Wisconsin
Merrill	Lincoln	Wisconsin
Milwaukee	Milwaukee	Wisconsin
Mosinee	Marathon	Wisconsin
Nekoosa	Wood	Wisconsin
Oak Creek	Milwaukee	Wisconsin
Owen	Clark	Wisconsin
Pt. Edwards	Wood	Wisconsin
Racine	Racine	Wisconsin
Rhinelander	Oneida	Wisconsin
Rothschild	Marathon	Wisconsin
Sheboygan	Sheboygan	Wisconsin
South Milwaukee	Milwaukee	Wisconsin
Stevens Point	Portage	Wisconsin
Stratford	Marathon	Wisconsin
Thorpe	Clark	Wisconsin
Tomahawk	Lincoln	Wisconsin
Waupun	Dodge	Wisconsin
Wausau	Marathon	Wisconsin
West Allis	Milwaukee	Wisconsin
Weyauwega	Waupaca	Wisconsin
Winnebago	Winnebago	Wisconsin
Wisconsin Dam	Lincoln	Wisconsin
Wisconsin Rapids	Wood	Wisconsin
Gladstone	Delta	Michigan
Marquette	Marquette	Michigan
Menominee	Menominee	Michigan
Ontonagon	Ontonagon	Michigan
Albert Lea	Freeborn	Minnesota
Austin	Mower	Minnesota

Table G - 2SO
(Cont'd)

City	County	State
Blue Earth	Fairbault	Minnesota
Fairmont	Martin	Minnesota
Hayward	Freeborn	Minnesota
Windom	Cottonwood	Minnesota
Worthington	Nobles	Minnesota
Campbell	Dunklin	Missouri
Chaffee	Scott	Missouri
Dolly Siding	St. Francois	Missouri
Jackson	Cape Girardeau	Missouri
Kirksville	Adair	Missouri
Mosher	Ste. Genevieve	Missouri
Morehouse	New Madrid	Missouri
Poplar Bluff	Butler	Missouri
S. Troy	Lincoln	Missouri
Trenton	Grundy	Missouri
Louisiana	Pike	Missouri
Clarksville	Pike	Missouri
Hannibal	Marion	Missouri
Ste. Genevieve	Ste. Genevieve	Missouri
Cape Girardeau	Cape Girardeau	Missouri
Paducah [Chiles]	McCracken	Kentucky

2. Coal Consumption by Non-Utility Facilities Located in Southern Sales Area

		Tons Consumed (000)		% of Total Consumption
Southern Production Consumed by Non-Utilities in Sales Area		2739		69%
Consumption of Coal Produced in Other Freight Rate Districts in Mining Districts 9, 10 & 11				
Fulton Peoria	47		1%	
Belleville	86		2%	
Mineral-Atkinson	57		1%	
West Kentucky	635		16%	
Indiana	400	1225	10%	30%
TOTAL CONSUMPTION BY NON-UTILITIES IN SALES AREA		3964		100%2/

(Cont'd)

3. Southern Production Sold to Non-Utilities

	Tons Produced (000)	% of Total Production
Sold to Non-Utilities in Sales Area	2739	44%
Sold to Greater Chicago Air Quality Control Region	1738	28%
Sold to Other Non-Utilities	1802	29%
TOTAL PRODUCTION SOLD TO NON-UTILITIES FROM MINES IN SOUTHERN FREIGHT DISTRICT	6279	100%

1/ Excluding sales of 1,931,092 tons of metallurgical coal from the Orient mines of Freeman, the Sahara mines of Sahara, Old Ben mine No. 21 and Zeigler mine No. 4.

2/ The apparent discrepancy between actual sum of the subtotals above and the total above is due to rounding. Each figure has been rounded to the nearest one percent.

Source: Government Questionnaire

Table G - 3SO

RECAPITULATION OF SALES OF
COAL PRODUCED IN THE
SOUTHERN (ILLINOIS) FREIGHT RATE DISTRICT

1. Coal Consumption by All Facilities in Southern Illinois Sales Area

		Tons Consumed (000)		% of Total Consumption
Southern Production Consumed by All Facilities in Sales Area		9971		52%
Consumption of Coal Produced in Other Freight Rate Districts in Mining Districts 9, 10 & 11				
Belleville1/	705		4%	
Fulton-Peoria	47		*	
Mineral-Atkinson	587		3%	
Murdock	91		*	
West Kentucky2/	6966		36%	
Indiana	728	9124	4%	47%
TOTAL CONSUMPTION OF COAL BY FACILITIES IN SALES AREA		19095		100%3/

Table G - 3SO
(Cont'd)

2. Southern Production Sold to All Facilities4/

	Tons Produced (000)	% of Total Production
Sold to Facilities in Sales Area	9971	65%
Sold to Commonwealth Edison	120	1%
Sold to Chicago Air Quality Control Region	1738	11%
Sold to Other Facilities5/	3555	23%
TOTAL	15384	100%

1/ Includes (1) 213,000 tons (3%) from the Fidelity Mine of United Electric to the Shawnee plant of TVA in Paducah, Kentucky, shipped under a Freeman contract. In response to Form 150 of the Subpoena Questionnaire, TVA received no other Belleville Freight District coal. In response to the Government questionnaire, no other Belleville producer reported sales to TVA. See also, Nugent Dep. Tr. p. 235. (2) Also includes 132,000 tons (2%) from the Fidelity mine of United Electric to the Weston plant of Wisconsin Power & Light in Green Bay, Wisconsin shipped under a Freeman contract. See also Morrison Dep. Tr. p. 18.

2/ Included within West Kentucky total is a one-third allocation [185,805.90] of the 557,417.70 tons shipped in 1967 from Tab-Badgett Lakeview Mine to "T.V.A.'s Widow Creek, Gallatin, and Shawnee Plants." In the absence of any evidence to the contrary, one-third of the aggregate tonnage has been attributed as the portion shipped to the Shawnee Plant in the Southern Utility Sales Area.

3/ The apparent discrepancy between actual sum of the subtotals above and the total above is due to rounding. Each figure has been rounded to the nearest one percent.

4/ Excluding sales of 1,931,092 tons of metallurgical coal from the Orient mines of Freeman, the Sahara mines of Sahara, Old Ben mine No. 21 and Zeigler Mine No. 4.

5/ Excludes 1,171,337 tons of dust from various mines to Belleville sales area utilities. See Footnote 2, Table G-1B.

Table G - P

SALE OF COAL TO FACILITIES LOCATED IN THE METROPOLITAN CHICAGO AIR QUALITY CONTROL REGION1/

Coal Consumption by Facilities Located in Chicago Air Quality Control Region

FROM FREIGHT RATE DISTRICT:	Tons Consumed (000)	% of Total Consumption
Southern	1738	24%
Fulton-Peoria	1004	14%
Belleville	2042	28%
Springfield	19	*
Northern Illinois	542	7%
Indiana	1113	15%
West Kentucky	865	12%
Danville	38	1%
TOTAL CONSUMPTION	7361	100%2/

1/ The Metropolitan Chicago Interstate Air Quality Control Region, as designated 42 C.F.R. §81.14 (33 F. R. 17176, Nov. 20, 1968), consists of Lake, McHenry, Cook, Du Page, Kane and Will Counties in Illinois and Lake and Porter Counties in Indiana. Tonnage to Commonwealth Edison facilities has not been included.

2/ The apparent discrepancy between actual sum of the subtotals above and the total above is due to rounding. Each figure has been rounded to the nearest one percent.

Source: Government Questionnaire

Table G-X

RECAPITULATION OF SALES OF
COAL PRODUCED AND CONSUMED
IN SPECIFIED MARKETS
Tons
(000)

	------ FREIGHT RATE DISTRICT ------										
	Fulton-Peoria PRODUCTION		Springfield PRODUCTION		Belleville PRODUCTION		Southern PRODUCTION		Other* PRODUCTION	TOTAL CONSUMPTION	
CONSUMED BY:	Tons	%	Tons	%	Tons	%	Tons	%	Tons	Tons	%
Specified Utility Markets	1988	21%	1406	16%	8707	44%	8127	53%	8160	28,388	45%
Specified Non-Utility Markets	2418	25%	350	4%	2120	11%	3101	20%	1508	9,497	15%
Commonwealth Edison	3794	40%	7191	80%	6514	33%	120	1%	---	17,619	28%
Chicago Air Quality Control Region	1004	11%	19	*	2042	10%	1738	11%	2558	7,361	12%
										62,865	100%
										TOTAL PRODUCTION OF NAMED FRT. DISTRICTS. Tons	%
Total Production Consumed in Above Markets	9204	97%	8966	100%	19383	98%	13086	85%		50,639	94%
Production Consumed in Other Markets	313	3%	23	*	500	2%	2298	15%		3,134	6%
TOTAL	9517	100%	8989	100%	19883	100%	15384	100%		53,773	100%
Single Freight Rate District Percentage of the Total Production of Named Frt. Dists.	18%		17%		37%		29%			100%	

Source: Tables G-1F, 2F; G-1S, 2S; G-1B, G-1SO, 2SO

* From other Freight Rate Districts in M[illegible]; Districts 9, 10 and 11.

DX 57

1980 UTILITY USE OF ILLINOIS COAL

Total Tons ALL COAL Used	Name of Utility	Tons of ILLINOIS COAL Used	Prime Source of Supply: Southern Illinois	Prime Source of Supply: Belleville Du Quoin	Prime Source of Supply: Fulton County	Prime Source of Supply: Central Illinois	Prime Source of Supply: Others Ill-Ind-Ky.
10,044,000	Commonwealth Edison	8,182,000		X	X	X	
12,418,000	T.V.A.	5,289,000	X				
5,018,000	Union Electric	3,016,000		X			
2,131,000	Illinois Power	2,131,000	X	X	X		D
5,229,000	Electric Energy	1,440,000	X				
1,481,000	Central Ill. Public Service	1,481,000	X	X	X		
2,727,000	Wisconsin Electric Power	1,205,000	X				
1,546,000	Northern States Power	1,118,000		X			
840,000	Central Illinois Light	840,000			X		
1,173,000	No. Indiana Public Service	505,000	X	X			
608,000	Wisconsin Public Service	495,000	X				
445,000	Interstate Power	445,000		X			
581,000	Iowa Electric Light & Power	440,000			X		A
428,000	Dairyland Power Coop.	400,000		X			
752,000	Wisconsin Power & Light	363,000		X			
238,000	Central Ill Gas & Electric	238,000	X	X			
227,000	Iowa-Illinois Gas & Electric	227,000					A
1,242,000	Consumers Power	220,000	X		X		

190,000	Springfield, Ill.	190,000				X
117,000	Lake Superior District Power	60,000	X			
64,000	NE Missouri Electric Power	64,000	X	X		
101,000	Iowa Public Service	62,000	X	X		
62,000	Central Elec Power-Chanois	62,000		X		
50,000	Muscatine, Iowa	50,000				
40,000	Hannibal, Mo.	40,000		X		
60,000	Upper Peninsula Power	40,000	X			
77,000	Missouri Utilities	35,000		X		
68,000	Manitowoc, Wis.	35,000	X			
4,092,000	Detroit Edison	18,000			X	
38,000	Mt. Carmel, Ill.	16,000	X			
1,317,000	Indiana & Michigan Electric	10,000				
25,000	Woodstock, Ill.	10,000	X			
27,000	Winnetka, Ill.	10,000	X			
49,826,000	Sub-total...	26,879,000				
	Miscellaneous	121,000				
	GRAND TOTAL ...	27,000,000				

1717

Total Illinois Sales Production for 1950 - 45,821,000

Utilities used 58.92% of Illinois Coal Produced-1950

38 -1072

DX 58

COAL SOLD UNDER CONTRACT
(1,000's of Tons)

Type Of Consumer	1967 Total Tons By Type	1967 Total Contract Tons	Annual Tonnage Committed Under Contracts Of Duration: 20 Years Or More	15-19 Years	10-14 Years	5-9 Years	1-4 Years	Tons Sold In 1967 By Method Other Than By Contract
Large Utilities	74,202 (100%)	66,497 (90%)	13,893 (19%)	20,120 (27%)	12,246 (17%)	9,986 (13%)	10,252 (14%)	7,705 (10%)
Small Utilities	2,329 (100%)	1,920 (82%)	0 (0%)	184 (8%)	157 (7%)	556 (24%)	1,023 (44%)	409 (18%)
Non-Utilities	13,752 (100%)	7,909 (58%)	598 (4%)	462 (3%)	45 --	2,099 (15%)	4,705 (34%)	5,843 (42%)

Source: Form 150, Subpoena Questionnaire.

DX 59

ANALYSIS OF POTENTIAL AND ACTUAL USE OF FUEL(S) OTHER THAN COAL BY COAL CONSUMING FACILITIES

	TABLE A GAS CAPABILITY 1/		TABLE B OIL CAPABILITY 1/	
Type of Consumer	# Facilities	# Coal Tons (add 000)	# Facilities	# Coal Tons (add 000)
LARGE UTILITIES:	38 [of 84] (45%)	23,281 [of 74,202] (31%)	12 [of 84] (14%)	12,148 [of 74,202] (16%)
SMALL UTILITIES:	5 [of 28] (18%)	385 [of 2,329] (17%)	6 [of 28] (21%)	886 [of 2,329] (38%)
MANUFACTURING FIRMS:	66 [of 160] (41%)	5,397 [of 12,657] (43%)	34 [of 160] (21%)	3,090 [of 12,657] (24%)
INSTITUTIONS:	5 [of 17] (29%)	264 [of 1,095] (24%)	9 [of 17] (53%)	833 [of 1,095] (76%)
TOTAL:	114 [of 289] (39%)	29,302 [of 90,283 total tons] (33%)	61 [of 289] (21%)	16,957 [of 90,283 total tons] (19%)

1/ Tables A and Table B are compilations of responses to Question #5, Form 175 [Coal Consuming Facility Questionnaire]. "Capability" to burn a given fuel other than coal exists if a particular facility is equipped to consume such fuel for any purpose, regardless of whether or not actual use occurred in 1967. The columns titled "# Tons" show the total tons of coal burned in 1967 at facilities which have the given capability. These tonnage figures are derived from responses to Form 150 of the Court-ordered Subpoena Questionnaire.

The distinction between the "Large Utilities" and "Small Utilities" is based upon a multi-dimensional comparison of the type of power system and the aggregate coal tonnage consumed within that system. Thus, the "Small" category consists of all co-operative and municipal power systems whose facilities consumed less than 500,000 tons of coal in the aggregate in 1967. The "Large" category consists of all corporate power companies, public and private, and all municipal or co-operative systems whose 1967 total coal consumption at all facilities combined was 500,000 tons or more.

TABLE C

GAS AND/OR OIL CAPABILITIES2/

	# Facilities	# Coal Tons (add 000)
LARGE UTILITIES	46 [of 84] (55%)	33,182 [of 74,202] (45%)
SMALL UTILITIES	9 [of 28] (32%)	1,157 [of 2,329] (50%)
MANUFACTURING FIRMS	73 [of 160] (46%)	5,873 [of 12,657] (46%)
INSTITUTIONS	11 [of 17] (65%)	877 [of 1,095] (80%)
TOTAL:	139 [289] (48%)	41,089 [90,283] (46%)

2/ Table C shows the number of facilities with gas, oil, or gas and oil capabilities. Thus, facilities with both gas and oil capabilities have been counted only once.

TABLE D

FREQUENCY DISTRIBUTION OF ACTUAL GAS USAGE - 1967 3/

[Number of Facilities]

	1-2 Months	3-5 Months	6-12 Months	Special Purposes	No Actual Use
LARGE UTILITIES [38 facilities]	X (0)	3 (8%)	30 (79%)	1 (3%)	4 (11%)
SMALL UTILITIES [5 facilities]	X (0)	1 (20%)	3 (60%)	X (0)	1 (20%)
MANUFACTURING [66 facilities]	X (0)	7 (11%)	42 (64%)	6 (9%)	11 (17%)
INSTITUTIONAL [5 facilities]	X (0)	2 (40%)	3 (60%)	X (0)	X (0)

3/ Table D is a compilation of responses to Question 6, Form 175 [Coal Consuming Facility Questionnaire]. The above groupings reflect actual natural gas usage in terms of months for the year 1967 by coal consuming facilities for which a response to the Subpoena Questionnaire was received, and a gas capability there indicated. "Special purposes" is the designation assigned for actual use solely for the purposes of start-up, peaking, or emergency. The percentages in parentheses are based upon the total number of facilities which have the capability to burn gas.

TABLE D-1

FREQUENCY DISTRIBUTION OF ACTUAL GAS USAGE - 1967 4/

[Number of Tons of Coal]
(add 000)

	1-2 Months	3-5 Months	6-12 Months	Special Purposes	No Actual Use
LARGE UTILITIES [23,281 tons]	X (0)	3,056 (13%)	19,025 (82%)	550 (2%)	650 (3%)
SMALL UTILITIES [385 tons]	X (0)	131 (34%)	201 (52%)	X (0)	53 (14%)
MANUFACTURING FIRMS [12,657 tons]	X (0)	354 (7%)	3,718 (69%)	347 (6%)	978 (18%)
INSTITUTIONS [264 tons]	X (0)	170 (64%)	94 (36%)	X (0)	X (0)

4/ Table D-1 is a compilation of responses to Question 6, Form 175 [Coal Consuming Facility Questionnaire. The tonnage figures represent the aggregate tons of coal purchased in 1967 for facilities actually using natural gas in the above frequencies, stated in terms of months for the year 1967. The percentages in parentheses are based upon the total number of tons of coal consumed in 1967 at facilities having the capability to burn gas. [All tonnage figures are derived from responses to Form 150 of the Questionnaire.]

TABLE E

FREQUENCY DISTRIBUTION OF ACTUAL OIL USAGE - 1967[5/]

[Number of Facilities]

	1-2 Months	3-5 Months	6-12 Months	Special Purposes	No Actual Use
LARGE UTILITIES [12 facilities]	X (0)	X (0)	4 (33%)	4 (33%)	4 (33%)
SMALL UTILITIES [6 facilities]	1 (17%)	X (0)	X (0)	1 (17%)	4 (67%)
MANUFACTURING FIRMS [34 facilities]	1 (3%)	5 (15%)	10 (29%)	8 (24%)	10 (29%)
INSTITUTIONS [9 facilities]	X (0)	1 (11%)	1 (11%)	2 (22%)	5 (56%)

5/ Table E is a compilation of responses to Question 6, Form 175 [Coal Consuming Facility Questionnaire]. The above groupings reflect actual oil usage in terms of months for the year 1967 by coal consuming facilities for which a response to the Subpoena Questionnaire was received. and an oil capability there indicated. "Special purposes" is the designation assigned for actual use solely for the purposes of start-up, peaking, or emergency. The percentages in parentheses are based upon the total number of facilities which have an oil capability.

TABLE E-1

FREQUENCY DISTRIBUTION OF ACTUAL OIL USAGE - 1967[6/]

[Number of Tons of Coal]
(add 000)

	1-2 Months	3-5 Months	6-12 Months	Special Purposes	No Actual Use
LARGE UTILITIES [12,148 tons]	X (0)	X (0)	2,507 (21%)	7,474 (62%)	2,167 (18%)
SMALL UTILITIES [886 tons]	114 (13%)	X (0)	X (0)	140 (16%)	632 (71%)
MANUFACTURING FIRMS [3,090 tons]	101 (3%)	244 (8%)	1,464 (47%)	552 (18%)	729 (24%)
INSTITUTIONS [833 tons]	X (0)	50 (6%)	80 (10%)	358 (43%)	345 (41%)

6/ Table E-1 is a compilation of responses to Question 6, Form 175 [Coal Consuming Facility Questionnaire]. The tonnage figures represent the aggregate tons of coal purchased in 1967 for facilities actually using oil in the above frequencies, stated in terms of months, for the year 1967. The percentages in parentheses are based upon the total number of tons of coal consumed in 1967 at facilities having the capability to burn oil. [All tonnage figures are derived from responses to Form 150 of the Questionnaire.]

TABLE F

Facilities [and the Corresponding Tons of Coal Purchased at Those Facilities in 1967] Equipped to Burn Gas for Each and Every Purpose for Which Coal Was Burned in 1967[7/]

	# of Facilities	# of Coal Tons
LARGE UTILITIES	37 (of 38) (97%)	22,852 (of 23,281) (98%)
SMALL UTILITIES	5 (of 5) (100%)	385 (of 385) (100%)
MANUFACTURING FIRMS	52 (of 66) (79%)	3,921 (of 5,397) (73%)
INSTITUTIONS	4 (of 5) (80%)	184 (of 264) (70%)

7/ Tons are rounded to Nearest 1,000. In the column headed "# of Facilities", the percentages in parentheses represent the ratio of the number of facilities equipped to burn gas for all of the purposes for which coal was burned in 1967 to the total number of all facilities with a gas capability. In the column headed "# of Coal Tons", the percentages in parentheses represent the ratio of the aggregate number of tons purchased by facilities which are equipped to burn gas for every purpose for which coal was burned in 1967 to the total number of tons of coal purchased by all facilities with a gas capability.

TABLE G

Facilities [and the Corresponding Tons of Coal Purchased at Those Facilities in 1967] Equipped to Burn Oil for Each and Every Purpose for Which Coal was Burned in 1967 8/

	# of Facilities	# of Coal Tons
LARGE UTILITIES	10 [of 12] (92%)	11,946 [of 12,148] (98%)
SMALL UTILITIES	6 [of 6] (100%)	886 [of 886] (100%)
MANUFACTURING FIRMS	27 [of 34] (79%)	1,917 [of 3,090] (62%)
INSTITUTIONS	7 [of 9] (78%)	584 [of 833] (70%)

8/ Tons are rounded to Nearest 1,000. In the column headed "# of Facilities", the percentages in parentheses represent the ratio of the number of facilities equipped to burn oil for all of the purposes for which coal was burned in 1967 to the total number of all facilities with an oil capability. In the column headed "# of Coal Tons", the percentages in parentheses represent the ratio of the aggregate number of tons purchased by facilities which are equipped to burn oil for every purpose for which coal was burned in 1967 to the total number of tons of coal purchased by all facilities with an oil capability.

THE UNITED ELECTRIC COAL COMPANIES
COAL RESERVE DATA

DX 60

(A) SUMMARY

	UEC COAL RESERVES AS OF DECEMBER 31, 1969
RESERVES DEDICATED TO EXISTING MINES	
CUBA, Fulton County, Illinois (Strip)	1,206,260
FIDELITY, Perry County, Illinois (Strip)	18,365,390
BUCKHEART AND NORTH CANTON, Fulton County, Illinois (Strip)	27,379,963
BANNER, Fulton and Peoria Counties, Illinois (Strip)	5,081,691
	52,033,304
UNDEVELOPED OR ISOLATED RESERVES	
Illinois Strip Reserves	
Industry Field Strip Reserves (McDonough County, Illinois)	12,550,457
Miscellaneous Illinois Strip Reserves	2,059,552
	14,610,009
Out-of-State Strip Reserves	
Oklahoma Strip Reserves	2,301,872
Colorado Strip Reserves	12,522,000
	14,823,872
Deep Reserves	
Fidelity Mine Deep Reserves	5,347,246
Round Prairie Field Deep Reserves (Perry and Washington Counties, Ill.)	44,251,574
Vermillion County, Illinois Deep Reserves	1,795,360
	51,394,180
Total Illinois Reserves	118,037,493
Total All Reserves	132,861,365

Source: The United Electric Coal Companies Lands and Reserve Coal and Depletion Schedule as of December 31, 1969.

(B) RESERVES 1958 - 1969

THE UNITED ELECTRIC COAL COMPANIES
LANDS & RESERVE COAL
AS OF DECEMBER 31, 1969

PAGE NO.	STRIP RESERVES	ESTIMATED RESERVE COAL: TOTAL ACRES	COAL ACRES	TONS	REMARKS
1, 2 & 3	Mine No. 9 - Cuba - Fulton County, Illinois	8,446.16	237.20	1,206,260	Active - Mining - Strip
4, 5, 6, 7, & 8	Mine No. 11 - Fidelity - Perry County, Illinois	11,538.93	2,237.33	18,363,390	Active - Mining - Strip
8 & 9	Clinch Field - Fidelity - Perry County, Illinois	1,300.28	-	-	Active - Mining - Strip
10 & 11	Mine No. 17 - North Buckheart - Fulton County, Illinois	5,739.33	695.79	5,798,376	Active - Mining - Strip
11, 12, 13, & 14	Mine No. 17 - South Buckheart - Fulton County, Illinois	8,113.30	1,366.37	10,225,623	Active - Mining - Strip
15	Mine No. 23 - Mary Moore - Vermillion County, Illinois	180.51	-	-	Inactive - Completed - 1958
16	Mine No. 27 - Banner - Fulton & Peoria Counties, Illinois	4,892.78	1,585.06	5,081,891	Active - Mining - Strip
	TOTAL - ACTIVE - MINING	40,373.46	6,311.02	40,677,328	
17 & 18	North Canton Field - Fulton County, Illinois	3,737.36	2,228.67	11,355,964	Inactive - Strip
19	Industry Field - McDonough & Schuyler Counties, Illinois	5,342.50	3,064.10	12,330,457	Inactive - Strip
20	East Liverpool - Fulton County, Illinois	160.00	103.23	364,842	Inactive - Strip
20	Gayle Field - Perry County, Illinois	358.96	223.63	1,714,710	Inactive - Strip
21	Hayden Field - Routt County, Colorado	5,937.47	712.60	12,122,000	Inactive - Strip
21	LeFlore County, Oklahoma	1,000.00	582.90	2,201,472	Inactive - Strip
	TOTAL - INACTIVE - MINING	16,536.29	7,317.93	40,789,867	
	GRAND TOTAL - STRIP RESERVES	56,909.73	14,028.93	81,467,185	

THE UNITED ELECTRIC COAL COMPANIES
LANDS & RESERVE COAL
AS OF DECEMBER 31, 1959

PAGE NO.	DEEP RESERVES	ESTIMATED RESERVE COAL TOTAL ACRES	COAL ACRES	TONS	REMARKS
21 & 22	Mine No. 11 - Fidelity - Perry County, Illinois	1,336.78	941.00	5,347,366	Inactive - Deep
23, 24 & 25	Round Prairie Field - Perry & Washington Counties, Illinois	7,399.74	7,316.74	42,885,772	Inactive - Deep
	TOTAL - INACTIVE - DEEP	8,736.52	8,258.62	48,133,010	
25	Round Prairie Field - Perry & Washington Counties, Illinois	109.00	109.00	441,801	Inactive - Isolated - Deep
25	Mine No. 31 - Buffalo Creek - Hopkins County, Kentucky	144.00	2.30	-	Inactive - Isolated - Deep
26	Moseis Property - Vermillion County, Illinois	313.00	310.05	1,250,000	Inactive - Isolated - Deep
26	Swallow Property - Vermillion County, Illinois	40.00	40.00	261,280	Inactive - Isolated - Deep
	TOTAL - INACTIVE - ISOLATED	606.00	461.35	2,193,161	
	GRAND TOTAL - DEEP RESERVES	9,342.52	8,719.97	51,594,180	
	TOTAL STRIP RESERVES	38,800.73	36,000.95	83,467,183	
	TOTAL DEEP RESERVES	9,342.52	8,719.97	51,594,180	
	GRAND TOTAL - RESERVES	48,133.05	53,740.97	135,061,363	

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THE UNITED ELECTRIC COAL COMPANIES
LANDS & RESERVE COAL
AS OF DECEMBER 31, 196[illegible]

PAGE NO.	STRIP RESERVES	ESTIMATED RESERVE COAL TOTAL ACRES	COAL ACRES	TONS	REMARKS
1, 2 & 3	Mine No. 9 - Gabe - Fulton County, Illinois	8,435.39	394.46	2,150,079	Active - Mining - Strip
4, 5, 6 & 7	Mine No. 11 - Fidelity - Perry County, Illinois	11,017.90	2,102.37	17,899,406	Active - Mining - Strip
8 & 9	Clinch Field - Fidelity - Perry County, Illinois	1,363.29	69.37	660,583	Active - Mining - Strip
10 & 11	Mine No. 17 - North Buckheart - Fulton County, Illinois	5,739.51	1,085.32	6,737,383	Active - Mining - Strip
11, 12, 13 & 14	Mine No. 17 - South Buckheart - Fulton County, Illinois	8,113.30	1,611.96	10,878,939	Active - Mining - Strip
15	Mine No. 25 - Mary Moore - Vermillion County, Illinois	160.51	-	-	Inactive - Completed - 1965
16	Mine No. 27 - Banner - Fulton & Peoria Counties, Illinois	4,991.72	1,910.88	6,050,031	Active - Mining - Strip
	TOTAL - ACTIVE - MINING	39,839.69	7,176.44	44,380,837	
17 & 18	North Canton Field - Fulton County, Illinois	3,737.36	3,320.67	11,353,966	Inactive - Strip
19	Industry Field - McDonough & Schuyler Counties, Illinois	5,341.50	3,448.10	13,550,457	Inactive - Strip
20	East Liverpool - Fulton County, Illinois	160.00	195.22	364,847	Inactive - Strip
20	Gayle Field - Perry County, Illinois	358.96	323.45	1,714,710	Inactive - Strip
21	Hayden Field - Routt County, Colorado	5,937.47	712.60	12,382,000	Inactive - Strip
21	LeFlore County, Oklahoma	1,010.00	282.95	1,301,877	Inactive - Strip
	TOTAL - INACTIVE - MINING	18,336.29	7,317.93	40,769,667	
	GRAND TOTAL - STRIP RESERVES	58,375.98	14,494.38	85,130,484	

THE UNITED ELECTRIC COAL COMPANIES
LANDS & RESERVE COAL
AS OF DECEMBER 31, [illegible]

PAGE NO.	DEEP RESERVES	ESTIMATED RESERVE COAL TOTAL ACRES	COAL ACRES	TONS	REMARKS
21 & 22	Mine No. 11 - Fidelity - Perry County, Illinois	1,336.78	941.88	5,347,266	Inactive - Deep
23, 24 & 25	Round Prairie Field - Perry & Washington Counties, Illinois	7,439.54	7,356.73	44,042,313	Inactive - Deep
	TOTAL - INACTIVE - DEEP	8,776.32	8,298.61	49,389,579	
25	Round Prairie Field - Perry & Washington Counties, Illinois	109.00	129.00	443,801	Inactive - Isolated - Deep
25	Mine No. 21 - Buffalo Creek - Hopkins County, Kentucky	144.00	1.30	-	Inactive - Isolated - Deep
26	Moore Property - Vermilion County, Illinois	313.00	310.00	1,550,000	Inactive - Isolated - Deep
26	Swallow Property - Vermilion County, Illinois	40.00	40.00	247,360	Inactive - Isolated - Deep
	TOTAL - INACTIVE - ISOLATED	606.00	441.30	2,241,161	
	GRAND TOTAL - DEEP RESERVES	9,385.32	8,739.91	51,630,740	
	TOTAL STRIP RESERVES	58,375.98	14,694.38	85,150,686	
	TOTAL DEEP RESERVES	9,385.32	8,739.92	51,630,740	
	GRAND TOTAL - RESERVES	67,761.30	23,434.30	136,781,426	

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PAGE NO.		TOTAL ACRES	ESTIMATED RESERVE COAL — COAL ACRES	ESTIMATED RESERVE COAL — TONS	REMARKS
1, 2 & 3	Mine No. 9 - Cuba - Fulton County, Illinois	8,284.93	605.06	3,719,654	Active - Mining - Strip
4, 5, 6 & 7	Mine No. 11 - Fidelity - Perry County, Illinois	10,932.30	2,264.39	19,195,050	Active - Mining - Strip
8 & 9	Clinch Field - Fidelity - Perry County, Illinois	1,360.86	84.28	781,200	Active - Mining - Strip
10 & 11	Mine No. 17 - North Buckheart - Fulton County, Illinois	5,739.52	1,160.14	7,605,810	Active - Mining - Strip
11, 12 & 13	Mine No. 17 - South Buckheart - Fulton County, Illinois	8,113.30	1,787.31	11,325,386	Active - Mining - Strip
14	Mine No. 25 - Mary Moore - Vermilion County, Illinois	65.21	-	-	Inactive - Completed - 1965
15 & 16	Mine No. 27 - Banner - Fulton & Peoria Counties, Illinois	4,992.78	2,160.70	6,864,992	Active - Mining - Strip
	TOTAL - ACTIVE - MINING	39,488.30	8,061.88	49,492,092	
17 & 18	North Canton Field - Fulton County, Illinois	5,737.36	2,228.67	11,355,966	Inactive - Strip
19	Industry Field - McDonough & Schuyler Counties, Illinois	5,342.50	3,668.10	12,550,457	Inactive - Strip
20	East Liverpool - Fulton County, Illinois	140.00	103.22	344,842	Inactive - Strip
20	Gaylo Field - Perry County, Illinois	358.96	272.43	1,714,710	Inactive - Strip
21	Hayden Field - Routt County, Colorado	5,937.47	712.60	12,522,000	Inactive - Strip
21	Buffalo Creek No. 2 - Hopkins & Christian Counties, Kentucky	-	-	-	In Process of Being Sold
21	LeFlore County, Oklahoma	1,020.00	532.90	2,301,872	Inactive - Strip
	TOTAL - INACTIVE - STRIP	18,536.29	7,517.92	40,789,847	
	GRAND TOTAL - STRIP RESERVES	58,024.59	15,579.80	91,281,939	

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PAGE NO.	DEEP RESERVES	ESTIMATED RESERVE COAL TOTAL ACRES	COAL ACRES	TONS	REMARKS
21 & 22	Mine No. 11 - Fidelity - Perry County, Illinois	1,336.78	940.74	5,342,280	Inactive - Deep
22	Buffalo Creek #8 - Hopkins & Christian Counties, Kentucky	-	-	-	In Process of Being Sold
23, 24 & 25	Round Prairie Field - Perry & Washington Counties, Illinois	7,439.74	7,356.74	44,042,333	Inactive - Deep
	TOTAL - INACTIVE - DEEP	8,776.52	8,297.48	49,384,613	
26	Round Prairie Field - Perry & Washington Counties, Illinois	109.00	109.00	445,801	Inactive - Isolated - Deep
26	Muncie Property - Vermilion County, Illinois	313.80	310.00	1,550,000	Inactive - Isolated - Deep
26	Swallow Property - Vermilion County, Illinois	40.00	40.00	245,360	Inactive - Isolated - Deep
26	Buffalo Creek #19 - Hopkins County, Kentucky	146.00	2.30	-	Inactive - Isolated
	TOTAL - INACTIVE - ISOLATED	608.80	461.30	2,241,161	
	GRAND TOTAL - DEEP RESERVES	9,385.32	8,758.78	51,625,774	
	TOTAL - STRIP RESERVES	58,024.59	15,519.80	91,281,939	
	TOTAL - DEEP RESERVES	9,385.32	8,758.78	51,625,774	
	GRAND TOTAL - RESERVES	67,409.91	24,278.58	142,907,713	

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		ESTIMATED RESERVE COAL			
PAGE NO.	STRIP RESERVES	TOTAL ACRES	COAL ACRES	TONS	REMARKS
1, 2 & 3	Mine No. 9 - Cuba - Fulton County, Illinois	8,231.81	729.00	4,491,713	Active - Mining - Strip
4, 5, 6 & 7	Mine No. 11 - Fidelity - Perry County, Illinois	10,891.30	2,481.15	21,090,483	Active - Mining - Strip
8 & 9	Clinch Field - Fidelity - Perry County, Illinois	1,360.86	84.80	781,200	Active - Mining - Strip
10 & 11	Mine No. 17 - North Buckheart - Fulton County, Illinois	5,739.52	1,321.10	8,852,617	Active - Mining - Strip
11, 12, 13 & 14	Mine No. 17 - South Buckheart - Fulton County, Illinois	8,113.30	1,853.83	12,105,501	Active - Mining - Strip
15	Mine No. 25 - Mary Moore - Vermilion County, Illinois	65.21	-		Inactive - Completed - 1965
15 & 16	Mine No. 27 - Banner - Fulton & Peoria Cos., Illinois	4,992.78	2,451.97	7,874,159	Active - Mining - Strip
	TOTAL - ACTIVE - MINING	39,393.58	8,921.33	54,995,413	
16, 17 & 18	North Canton Field - Fulton County, Illinois	5,737.36	2,228.67	11,355,966	Inactive - Strip
18	Gayle Field - Perry County, Illinois	358.96	222.43	1,714,710	Inactive - Strip
19	Industry Field - McDonough & Schuyler Cos., Illinois	5,342.50	3,668.10	12,550,457	Inactive - Strip
20	Hayden Field - Routt County, Colorado	5,937.47	712.60	18,522,000	Inactive - Strip
20	Buffalo Creek #2 - Hopkins & Christian Cos., Ky.	867.72	218.47	1,166,570	Inactive - Strip
21	LeFlore County, Oklahoma	1,000.00	582.90	2,301,872	Inactive - Strip
21	East Liverpool - Fulton County, Illinois	140.00	103.22	344,842	Inactive - Strip
	TOTAL - INACTIVE - STRIP	19,404.01	7,736.39	41,956,417	
	GRAND TOTAL - STRIP RESERVES	58,797.59	16,657.72	96,952,030	

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LANDS & RESERVE COAL
AS OF DECEMBER 31, 1946

PAGE NO.	DEEP RESERVES	TOTAL ACRES	ESTIMATED RESERVE COAL COAL ACRES	ESTIMATED RESERVE COAL TONS	REMARKS
21 & 22	Mine No. 11 - Fidelity - Perry County, Illinois	1,336.78	940.74	5,342,280	Inactive - Deep
22 & 23	Buffalo Creek #2 - Hopkins & Christian Cos., Kentucky	1,687.00	871.63	3,223,378	Inactive - Deep
23, 24 & 25	Round Prairie Field - Perry & Washington Cos., Illinois	7,321.74	7,238.74	43,337,153	Inactive - Deep
	TOTAL - INACTIVE - DEEP	10,345.52	9,051.11	51,902,811	
26	Round Prairie Field - Perry & Washington Cos., Illinois	109.00	109.00	545,981	Inactive - Isolated - Deep
26	Muncie Property - Vermilion County, Illinois	313.80	310.00	1,550,000	Inactive - Isolated - Deep
26	Swallow Property - Vermilion County, Illinois	40.00	40.00	245,360	Inactive - Isolated - Deep
	TOTAL - INACTIVE - ISOLATED - DEEP	462.80	459.00	2,341,341	
	GRAND TOTAL - DEEP RESERVES	10,808.32	9,510.11	54,244,152	
	TOTAL - STRIP RESERVES	58,797.59	16,657.72	96,952,030	
	TOTAL - DEEP RESERVES	10,808.32	9,510.11	54,244,152	
	GRAND TOTAL - RESERVES	69,605.91	26,167.83	151,196,182	

THE UNITED ELECTRIC COAL COMPANIES
LANDS & RESERVE COAL
AS OF DECEMBER 31, 1945

PAGE NO.	DEEP RESERVES	ESTIMATED RESERVE COAL TOTAL ACRES	COAL ACRES	TONS	REMARKS
19 & 20	Mine No. 11 - Fidelity - Perry County, Illinois	1,356.54	898.50	5,114,180	Inactive - Deep
20 & 21	Buffalo Creek No. 1 - Hopkins & Christian Counties, Kentucky	1,487.00	903.22	3,388,857	Inactive - Deep
21, 22 & 23	Round Prairie Field - Perry & Washington Counties, Illinois	7,321.74	7,238.74	43,337,153	Inactive - Deep
	TOTAL - INACTIVE - DEEP	10,165.28	9,040.46	51,780,190	
24	Round Prairie Field - Perry & Washington Counties, Illinois	109.00	109.00	545,981	Inactive - Isolated - Deep
24	Pancie Property - Vermilion County, Illinois	313.80	310.00	1,550,000	Inactive - Isolated - Deep
24	Swallow Property - Vermilion County, Illinois	40.00	40.00	245,360	Inactive - Isolated - Deep
	TOTAL - INACTIVE - ISOLATED - DEEP	462.80	459.00	2,341,341	
	GRAND TOTAL - DEEP RESERVES	10,628.08	9,499.46	54,121,531	
	TOTAL - STRIP RESERVES	58,912.62	17,325.61	100,830,922	
	TOTAL - DEEP RESERVES	10,628.08	9,499.46	54,121,531	
	GRAND TOTAL - RESERVES	69,540.70	26,825.07	154,952,453	

THE UNITED ELECTRIC COAL COMPANIES
LANDS & RESERVE COAL
AS OF DECEMBER 31, 1965

PAGE NO.	STRIP RESERVES	ESTIMATED RESERVE COAL TOTAL ACRES	COAL ACRES	TONS	REMARKS
1, 2 & 3	Mine No. 9 - Cuba - Fulton County, Illinois	8,151.21	566.72	5,316,062	Active - Mining - Strip
3, 4, 5 & 6	Mine No. 11 - Fidelity - Perry County, Illinois	10,693.75	2,626.93	22,372,333	Active - Mining - Strip
6, 7 & 8	Climb Field - Fidelity - Perry County, Illinois	1,360.26	84.88	781,200	Active - Mining - Strip
8 & 9	Mine No. 17 - North Buckheart - Fulton County, Illinois	5,739.52	1,567.55	10,247,792	Active - Mining - Strip
9, 10, 11 & 12	Mine No. 17 - South Buckheart - Fulton County, Illinois	7,598.01	1,696.55	11,163,665	Active - Mining - Strip
12 & 13	Mine No. 25 - Mary Moore - Vermilion County, Illinois	723.82	-	-	Inactive - Completed - 1965
14	Mine No. 27 - Banner - Fulton & Peoria Counties, Illinois	4,952.78	2,723.76	8,760,625	Active - Mining - Strip
	TOTAL - ACTIVE - MINING	39,219.35	9,546.29	58,641,676	
15 & 16	North Canton Field - Fulton County, Illinois	5,737.36	2,328.67	11,355,966	Active - Prospecting - Strip
17	Gayle Field - Perry County, Illinois	457.22	272.43	1,714,710	Active - Prospecting - Strip
17 & 18	Industry Field - McDonough & Schuyler Counties, Illinois	5,362.50	3,600.10	12,550,457	Active - Prospecting - Strip
18 & 19	Buffalo Creek No. 2 - Hopkins & Christian Counties, Kentucky	1,058.72	862.40	1,399,399	Active - Prospecting - Strip
24	Hayden Field - Routt County, Colorado	5,937.47	712.60	12,528,000	Active - Prospecting - Strip
19	LeFlore County, Oklahoma	1,000.00	582.90	2,301,872	Inactive - Strip
19	East Liverpool - Fulton County, Illinois	140.00	103.22	341,842	Inactive - Strip
	TOTAL - INACTIVE - STRIP	19,693.27	7,780.32	42,189,246	
	GRAND TOTAL - STRIP RESERVES	58,912,62	17,325.61	100,830,922	

THE UNITED ELECTRIC COAL COMPANIES
LANDS & RESERVE COAL
AS OF DECEMBER 31, 1964

PAGE NO.	STRIP RESERVES	ESTIMATED RESERVE COAL TOTAL ACRES	COAL ACRES	TONS	REMARKS
1 & 2	Mine No. 9 - Cuba - Fulton County, Illinois	6,238.53	303.22	8,034,370	Active - Mining - Strip
3, 4, 5 & 6	Mine No. 11 - Fidelity - Perry County, Illinois	10,676.35	2,928.29	25,065,515	Active - Mining - Strip
6, 7 & 8	Climax Field - Fidelity - Perry County, Illinois	1,360.26	84.28	781,200	Active - Mining - Strip
9	Mine No. 17 - North Buckheart - Fulton County, Illinois	5,545.32	1,841.04	11,984,089	Active - Mining - Strip
10, 11 & 12	Mine No. 17 - South Buckheart - Fulton County, Illinois	7,278.01	1,431.55	9,388,255	Active - Mining - Strip
13 & 14	Mine No. 25 - Mary Moore - Vermilion County, Illinois	722.81	2.27	19,215	Active - Mining - Strip
14 & 15	Mine No. 27 - Banner - Fulton & Peoria Counties, Illinois	4,462.73	2,461.49	8,006,781	Active - Mining - Strip
	TOTAL - ACTIVE - MINING	36,284.01	9,052.14	57,279,455	
15, 16 & 17	North Canton Field - Fulton County, Illinois	4,842.60	3,361.82	17,518,954	Inactive - Strip
17	Gayle Field - Perry County, Illinois	457.22	222.43	1,714,710	Inactive - Strip
18	Industry Field - McDonough & Schuyler Counties, Illinois	5,362.50	3,668.10	12,550,457	Inactive - Strip
19	Buffalo Creek No. 2 - Hopkins & Christian Counties, Kentucky	1,058.72	862.10	1,399,399	Inactive - Strip
19	LeFlore County, Oklahoma	1,020.00	582.90	2,301,872	Inactive - Strip
20	East Liverpool - Fulton County, Illinois	140.00	103.22	344,848	Inactive - Strip
	TOTAL - INACTIVE - STRIP	12,881.04	8,200.87	35,830,234	
	GRAND TOTAL - STRIP RESERVES	49,165.05	17,253.01	93,109,689	

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PAGE NO.	DEEP RESERVES	ESTIMATED RESERVE COAL: TOTAL ACRES	COAL ACRES	TONS	REMARKS
20 & 21	Mine No. 11 - Fidelity - Perry County, Illinois	1,356.54	898.50	5,114,180	Inactive - Deep
21 & 22	Buffalo Creek No. 2 - Hopkins & Christian Counties, Kentucky	2,055.50	1,063.22	3,793,497	Inactive - Deep
22, 23 & 24	Round Prairie Field - Perry & Washington Counties, Illinois	6,255.74	6,172.74	37,207,182	Inactive - Deep
	TOTAL - INACTIVE - DEEP	9,667.78	8,134.46	46,114,859	
24	Round Prairie Field - Perry & Washington Counties, Illinois	109.00	109.00	545,981	Inactive - Isolated - Deep
25	Muncie Property - Vermilion County, Illinois	313.80	310.00	1,550,000	Inactive - Isolated - Deep
25	Swallow Property - Vermilion County, Illinois	40.00	40.00	245,360	Inactive - Isolated - Deep
	TOTAL - INACTIVE - ISOLATED - DEEP	462.80	459.00	2,341,341	
	GRAND TOTAL - DEEP RESERVES	10,130.58	8,593.46	48,456,200	
	TOTAL - STRIP RESERVES	49,145.05	17,253.01	93,109,689	
	TOTAL - DEEP RESERVES	10,130.58	8,593.46	48,456,200	
	GRAND TOTAL - RESERVES	59,275.63	25,846.47	141,565,889	

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PAGE NO.	STRIP RESERVES	ESTIMATED RESERVE COAL TOTAL ACRES	COAL ACRES	TONS	REMARKS
1 & 2	Mine No. 9 - Cuba - Fulton County, Illinois	6,238.53	367.87	8,446,235	Active - Mining - Strip
3, 4, 5 & 6	Mine No. 11 - Fidelity - Perry County, Illinois	10,675.35	3,009.21	25,737,362	Active - Mining - Strip
6, 7 & 8	Clinch Field - Fidelity - Perry County, Illinois	1,360.26	84.28	781,200	Active - Mining - Strip
9	Mine No. 17 - North Buckheart - Fulton County, Illinois	5,458.92	1,971.64	12,803,936	Active - Mining - Strip
10, 11 & 12	Mine No. 17 - South Buckheart - Fulton County, Illinois	7,278.01	1,431.55	9,388,285	Active - Mining - Strip
13 & 14	Mine No. 25 - Mary Moore - Vermilion County, Illinois	772.81	11.89	95,180	Active - Mining - Strip
14 & 15	Mine No. 27 - Banner - Fulton & Peoria Counties, Illinois	4,339.99	2,486.12	2,081,841	Active - Mining - Strip
	TOTAL - ACTIVE - MINING	36,123.87	9,362.56	59,334,039	
15, 16 & 17	North Canton Field - Fulton County, Illinois	4,842.60	3,361.82	17,518,954	Active - Prospecting - Strip
17	Gayle Field - Perry County, Illinois	457.22	282.43	1,714,710	Active - Prospecting - Strip
18	Industry Field - McDonough & Schuyler Counties, Illinois	5,342.50	3,668.10	12,550,457	Active - Prospecting - Strip
19	Buffalo Creek No. 2 - Hopkins & Christian Counties, Kentucky	1,058.72	862.40	1,379,379	Active - Prospecting - Strip
19	LeFlore County, Oklahoma	1,020.00	582.90	2,301,872	Inactive - Strip
20	East Liverpool - Fulton County, Illinois	140.00	103.22	344,862	Inactive - Strip
	TOTAL - INACTIVE - STRIP	12,861.04	8,220.87	35,830,234	
	GRAND TOTAL - STRIP RESERVES	48,984.91	17,583.43	95,164,273	

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PAGE NO.	DEEP RESERVES	ESTIMATED RESERVE COAL TOTAL ACRES	COAL ACRES	TONS	REMARKS
20 & 21	Mine No. 11 - Fidelity - Perry County, Illinois	1,356.54	898.50	5,114,180	Inactive - Deep
21 & 22	Buffalo Creek No. 8 - Hopkins & Christian Counties, Kentucky	2,055.50	1,063.22	3,793,497	Inactive - Deep
22, 23 & 24	Round Prairie Field - Perry & Washington Counties, Illinois	6,215.74	6,132.74	36,974,862	Inactive - Deep
	TOTAL - INACTIVE - DEEP	9,627.78	8,094.46	45,882,539	
24	Round Prairie Field - Perry & Washington Counties, Illinois	109.00	109.00	545,981	Inactive - Isolated - Deep
25	Mussie Property - Vermilion County, Illinois	313.80	310.00	1,550,000	Inactive - Isolated - Deep
25	Swallow Property - Vermilion County, Illinois	40.00	40.00	245,360	Inactive - Isolated - Deep
	TOTAL - INACTIVE - ISOLATED - DEEP	462.80	459.00	2,341,341	
	GRAND TOTAL - DEEP RESERVES	10,090.58	8,553.46	48,223,880	
	TOTAL - STRIP RESERVES	48,984.91	17,563.43	95,164,273	
	TOTAL - DEEP RESERVES	10,090.58	8,553.46	48,223,880	
	GRAND TOTAL - RESERVES	59,075.49	26,116.89	143,388,153	

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LANDS & RESERVE COAL
AS OF JULY 31, 1963

PAGE NO.	STRIP RESERVES	ESTIMATED RESERVE COAL TOTAL ACRES	COAL ACRES	TONS	REMARKS
1 & 2	Mine No. 9 - Cuba - Fulton County, Illinois	5,806.60	813.86	1,449,206	Active - Mining - Strip
3, 4, 5 & 6	Mine No. 11 - Fidelity - Perry County, Illinois	10,428.55	3,078.65	18,885,346	Active - Mining - Strip
6 & 7	Clinch Field - Fidelity - Perry County, Illinois	1,360.86	84.38	781,200	Active - Mining - Strip
8	Mine No. 17 - North Buckheart - Fulton County, Illinois	5,383.92	2,111.50	13,752,368	Active - Mining - Strip
9, 10 & 11	Mine No. 17 - South Buckheart - Fulton County, Illinois	6,650.75	1,868.95	8,275,085	Active - Mining - Strip
12 & 13	Mine No. 25 - Mary Moore - Vermilion County, Illinois	544.99	41.88	345,521	Active - Mining - Strip
13 & 14	Mine No. 27 - Banner - Fulton & Peoria Counties, Illinois	3,782.44	2,320.86	7,095,070	Active - Mining - Strip
	TOTAL - ACTIVE - MINING	33,957.61	9,120.82	50,583,796	
14 & 15	North Canton Field - Fulton County, Illinois	4,629.27	3,196.88	16,522,354	Active - Prospecting - Strip
15 & 16	Gayle Field - Perry County, Illinois	457.22	229.43	1,714,710	Active - Prospecting - Strip
16 & 17	Industry Field - McDonough County, Illinois	4,970.50	3,476.10	11,950,457	Active - Prospecting - Strip
17 & 18	Buffalo Creek #2 - Hopkins & Christian Counties, Kentucky	1,058.72	262.40	1,379,399	Active - Prospecting - Strip
	TOTAL - ACTIVE - PROSPECTING	11,115.71	7,157.75	31,566,920	
18	LeFlore County, Oklahoma	1,000.00	582.90	2,301,872	Inactive - Strip
18	South Buckheart - Isolated - Fulton County, Illinois	160.00	103.22	344,842	Inactive - Strip
	TOTAL - INACTIVE - STRIP	1,160.00	686.12	2,646,714	
	GRAND TOTAL - STRIP RESERVES	46,233.32	16,964.69	92,817,430	

THE UNITED ELECTRIC COAL COMPANIES
LANDS & RESERVE COAL
AS OF JULY 31, 1963

PAGE NO.	DEEP RESERVES	ESTIMATED RESERVE COAL TOTAL ACRES	COAL ACRES	TONS	REMARKS
18 & 19	Mine No. 11 - Fidelity - Perry County, Illinois	1,356.54	898.50	5,114,180	Inactive - Deep
19 & 20	Buffalo Creek #2 - Hopkins & Christian Counties, Kentucky	2,055.50	1,063.22	3,793,497	Inactive - Deep
21 & 22	Round Prairie Field - Perry County, Illinois	3,934.24	3,051.24	23,681,781	Inactive - Deep
	TOTAL - INACTIVE - DEEP	7,346.28	5,012.96	32,589,458	
22	Round Prairie Field - Perry County, Illinois	109.00	109.00	545,981	Inactive - Isolated - Deep
23	Mussie Property	313.80	310.00	1,550,000	Inactive - Isolated - Deep
23	Swallow Property	40.00	40.00	245,360	Inactive - Isolated - Deep
	TOTAL - INACTIVE - ISOLATED	462.80	459.00	2,341,341	
	GRAND TOTAL - DEEP RESERVES	7,809.08	6,471.96	34,930,799	
	TOTAL - STRIP RESERVES	46,233.22	16,964.69	92,817,430	
	TOTAL - DEEP RESERVES	7,809.08	6,471.96	34,930,799	
	GRAND TOTAL - RESERVES	54,042.30	23,436.65	127,748,229	

THE UNITED ELECTRIC COAL COMPANIES
LANDS & RESERVE COAL
AS OF JULY 31, 1962

PAGE NO.	STRIP RESERVES	TOTAL ACRES	ESTIMATED RESERVE COAL: COAL ACRES	ESTIMATED RESERVE COAL: TONS	REMARKS
1 & 2	Mine No. 9 - Cuba - Fulton County, Illinois	5,806.60	334.60	2,858,105	Active - Mining - Strip
3, 4, 5 & 6	Mine No. 11 - Fidelity - Perry County, Illinois	9,751.80	2,583.49	24,968,675	Active - Mining - Strip
6 & 7	Gilch Field - Fidelity - Perry County, Illinois	1,360.86	84.28	781,200	Active - Mining - Strip
8, 9, 10 & 11	Mine No. 17 - Buckheart - Fulton County, Illinois Mine No 17 South Buckheart - Fulton Co, Illinois	11,938.84	3,442.74	27,300,294	Active - Mining - Strip
12 & 13	Mine No. 25 - Mary Moore - Vermilion County, Illinois	723.06	73.37	628,135	Active - Mining - Strip
13 & 14	Mine No. 27 - Banner - Fulton & Peoria Counties, Illinois	3,566.07	2,409.40	7,418,082	Active - Mining - Strip
	TOTAL - ACTIVE - MINING	33,145.43	9,067.88	58,988,491	
15 & 16	North Canton Field - Fulton County, Illinois	3,370.94	1,836.35	11,490,539	Active - Prospecting - Strip
16	Gayle Field - Perry County, Illinois	457.88	188.43	1,714,710	Active - Prospecting - Strip
17	Industry Field - McDonough County, Illinois	4,847.80	3,371.10	11,479,017	Active - Prospecting - Strip
18	Buffalo Creek #2 - Hopkins & Christian Counties, Kentucky	1,058.72	242.40	1,[illegible]	Active - Prospecting - Strip
	TOTAL - ACTIVE - PROSPECTING	9,734.35	5,218.28	26,303,665	
18	LeFlore County, Oklahoma	1,000.00	582.90	9,301,872	Inactive - Strip
18	South Buckheart (Isolated) - Fulton County, Illinois	140.00	103.22	344,842	Inactive - Isolated - Strip
	TOTAL - INACTIVE - STRIP	1,140.00	686.12	9,646,714	
	GRAND TOTAL - STRIP RESERVES	44,039.78	14,066.28	98,078,810	

THE UNITED ELECTRIC COAL COMPANIES
LANDS & RESERVE COAL
AS OF JULY 31, 1962

PAGE NO.	DEEP RESERVE	ESTIMATED RESERVE COAL TOTAL ACRES	COAL ACRES	TONS	REMARKS
19	Mine No. 12 - Fidelity - Perry County, Illinois	1,356.54	898.50	5,114,180	Inactive - Deep
20 & 21	Buffalo Creek #2 - Hopkins & Christian Counties, Kentucky	2,055.50	1,143.22	4,083,897	Inactive - Deep
21 & 22	Round Prairie Field - Perry County, Illinois	4,043.24	3,960.24	24,227,762	Inactive - Deep
	TOTAL - INACTIVE - DEEP	7,455.28	6,001.96	33,425,839	
23	Mussie Property - Vermilion County, Illinois	313.80	310.00	1,350,000	Inactive - Isolated - Deep
23	Swallow Property - Vermilion County, Illinois ADD ROUND PRAIRIE DEEP ISOLATED	40.00	40.00	445,360	Inactive - Isolated - Deep
	TOTAL - INACTIVE - ISOLATED	353.80	350.00	1,795,360	
	GRAND TOTAL - DEEP RESERVES	7,809.08	6,351.96	35,221,199	
	TOTAL - STRIP RESERVES TOTAL - DEEP RESERVES	44,039.78 7,809.08	16,066.28 6,351.96	88,078,810 35,221,199	
	GRAND TOTAL - RESERVES	51,848.86	22,418.24	123,300,009	

THE UNITED ELECTRIC COAL COMPANIES
LANDS & [illegible] COAL
AS OF JULY 31, 1961

MAP NO.	STRIP RESERVES	ESTIMATED [illegible] COAL TOTAL ACRES	COAL ACRES	TONS	REMARKS
1 & 2	Mine No. 9 - Cuba - Fulton County, Illinois	5,865.40	457.73	3,024,764	Active - Mining - Strip
3, 4, 5 & 6	Mine No. 11 - Fidelity - Perry County, Illinois	9,751.30	3,119.08	26,594,317	Active - Mining - Strip
6 & 7	Cliant Field - Fidelity - Perry County, Illinois	1,350.26	84.28	781,200	Active - Mining - Strip
8, 9 & 10	Mine No. 17 - Buckheart - Fulton County, Illinois	11,179.74	3,106.43	20,195,130	Active - Mining - Strip
11 & 12	Mine No. 25 - Mary Moore - Vermilion County, Illinois	566.16	26.17	171,500	Active - Mining - Strip
12	Mine No. 27 - Bruner - Fulton & Peoria Counties, Illinois	3,551.12	2,501.83	8,420,026	Active - Mining - Strip
	TOTAL - ACTIVE - MINING	32,164.73	9,375.52	59,177,507	
13	North Canton Field - Fulton County, Illinois	2,712.74	1,760.15	9,277,130	Active - Prospecting - Strip
14	Gayle Field - Perry County, Illinois	481.12	222.43	1,714,730	Active - Prospecting - Strip
15	Industry Field - McDonough County, Illinois	4,847.[illegible]	3,391.10	11,699,017	Active - Prospecting - Strip
16	Buffalo Creek #2 - Hopkins & Christian Counties, Kentucky	[illegible] 1,052.72	268.40	1,399,399	Active - Prospecting - Strip
	TOTAL - ACTIVE - PROSPECTING	[illegible] 9,0[illegible]	5,644.08	24,090,256	
16	LeFlore County, Oklahoma	[illegible] 148.90	582.90	8,301,872	Inactive - Strip
16	South Buckheart Field - Fulton County, Illinois	[illegible]	103.22	314,842	Inactive - Isolated - Strip
	TOTAL - INACTIVE - STRIP	1,1[illegible].40	686.12	8,616,714	
	GRAND TOTAL - STRIP RESERVES	[illegible] 42,420.00	15,705.72	85,914,477	

THE UNITED ELECTRIC COAL COMPANIES
LANDS & RESERVE COAL
AS OF JULY 31, 1961

PAGE NO.	DEEP RESERVES	ESTIMATED RESERVE COAL TOTAL ACRES	COAL ACRES	TONS	REMARKS
17 & 18	Buffalo Creek No. 8 - Hopkins & Christian Counties, Kentucky	2,055.50	1,143.22	4,083,897	Inactive - Deep
19	Mine No. 11 - Fidelity - Perry County, Illinois	1,356.54	908.50	5,114,180	Inactive - Deep
20 & 21	Round Prairie Field - Perry County, Illinois	4,043.94	3,950.24	24,227,762	Inactive - Deep
	TOTAL - INACTIVE - DEEP	7,455.98	6,001.96	33,425,839	
22	Salt Fork Field - Vermilion County, Illinois	136.00	116.00	691,152	Inactive - Isolated - Deep
22	Morris Property - Vermilion County, Illinois	313.00	310.00	1,550,000	Inactive - Isolated - Deep
22	Swallow Property - Vermilion County, Illinois	40.00	40.00	265,360	Inactive - Isolated - Deep
	TOTAL - INACTIVE - ISOLATED	489.00	466.00	2,506,512	
	GRAND TOTAL - DEEP RESERVES	7,944.98	6,467.96	35,932,351	
	TOTAL - STRIP RESERVES	42,420.26	15,705.72	85,954,477	
	TOTAL - DEEP RESERVES	7,944.98	6,467.96	35,932,351	
	GRAND TOTAL - RESERVES	50,365.24	22,173.68	121,886,828	

THE UNITED ELECTRIC COAL COMPANIES
LANDS & RESERVE COAL
AS OF JULY 31, 1960

PAGE NO.	STRIP RESERVES	TOTAL ACRES	ESTIMATED RESERVE COAL — COAL ACRES	ESTIMATED RESERVE COAL — TONS	REMARKS
1 & 2	Mine No. 9 - Cuba - Fulton County, Illinois	5,806.60	507.19	3,909,179	Active - Mining - Strip
3, 4, 5 & 6	Mine No. 11 - Fidelity - Perry County, Illinois	9,750.20	3,323.69	28,353,657	Active - Mining - Strip
6 & 7	Clinch Field - Fidelity - Perry County, Illinois	1,360.26	84.28	781,200	Active - Mining - Strip
8, 9 & 10	Mine No. 17 - Buckheart - Fulton County, Illinois	11,045.12	3,283.54	21,299,311	Active - Mining - Strip
11	Mine No. 25 - Mary Moore - Vermilion County, Illinois	398.79	4.31	30,300	Active - Mining - Strip
12	Mine No. 27 - Banner - Fulton & Peoria Counties, Illinois	3,291.45	2,610.80	8,867,227	Active - Mining - Strip
	TOTAL - ACTIVE - MINING	31,652.42	9,893.81	63,240,874	
13	North Canton Field - Fulton County, Illinois	2,552.74	1,672.15	8,753,030	Active - Prospecting - Strip
14	Coyle Field - Perry County, Illinois	457.22	222.43	1,714,710	Active - Prospecting - Strip
15	Industry Field - McDonough County, Illinois	4,727.50	3,339.10	11,589,717	Active - Prospecting - Strip
16	Buffalo Creek #2 - Hopkins & Christian Counties, Kentucky	1,058.72	262.40	1,292,399	Active - Prospecting - Strip
	TOTAL - ACTIVE - PROSPECTING	8,796.18	5,496.08	23,386,056	
15	LeFlore County, Oklahoma	1,020.00	502.90	2,301,872	Inactive - Strip
16	South Buckheart Field - Fulton County, Illinois	140.00	103.22	344,842	Inactive - Isolated - Strip
	TOTAL - INACTIVE - STRIP	1,160.00	606.12	2,646,714	
	GRAND TOTAL - STRIP RESERVES	41,608.60	16,076.01	89,292,444	

THE UNITED ELECTRIC COAL COMPANIES
ACRES & RESERVE COAL
AS OF JULY 31, 1960

PAGE NO.	DEEP RESERVES	ESTIMATED RESERVE COAL TOTAL ACRES	COAL ACRES	TONS	REMARKS
17 & 18	Buffalo Creek No. 2 - Hopkins & Christian Counties, Kentucky	2,055.5[illegible]	1,143.22	4,083,877	Inactive - Deep
19	Mine No. 11 - Fidelity - Perry County, Illinois	1,356.54	898.50	5,114,180	Inactive - Deep
20 & 21	Round Prairie Field - Perry County, Illinois	3,703.2[illegible]	3,620.24	22,253,062	Inactive - Deep
	TOTAL - INACTIVE - DEEP	7,115.28	5,661.96	31,451,119	
22	Salt Fork Field - Vermilion County, Illinois	136.00	136.00	691,152	Inactive - Isolated - Deep
22	Hassie Property - Vermilion County, Illinois	313.80	310.00	1,550,000	Inactive - Isolated - Deep
22	Smalley Property - Vermilion County, Illinois	40.00	40.00	245,360	Inactive - Isolated - Deep
	TOTAL - INACTIVE - DEEP	489.80	486.00	2,486,512	
	GRAND TOTAL - DEEP RESERVES	7,605.08	6,147.96	33,937,631	
	TOTAL - STRIP RESERVES	41,808.60	16,076.01	89,292,444	
	TOTAL - DEEP RESERVES	7,605.08	6,147.96	33,937,631	
	GRAND TOTAL - RESERVES	49,413.68	22,223.97	123,230,075	

THE UNITED ELECTRIC COAL COMPANIES
LANDS & RESERVE COAL
AS OF JULY 31, 1957

PAGE NO.	STRIP RESERVES	ESTIMATED RESERVE COAL TOTAL ACRES	COAL ACRES	TONS	REMARKS
1 & 2	Mine No. 9 - Cuba - Fulton County, Illinois	5,806.60	730.38	4,894,127	Active - Mining - Strip
3, 4 & 5	Mine No. 11 - Fidelity - Perry County, Illinois	9,384.20	3,306.15	28,250,953	Active - Mining - Strip
6 & 7	Clinch Field - Fidelity - Perry County, Illinois	1,360.26	106.11	971,068	Active - Mining - Strip
8, 9 & 10	Mine No. 17 - Buckheart - Fulton County, Illinois	11,141.18	3,446.72	22,311,761	Active - Mining - Strip
10	Mine No. 19 - Buffalo Creek - Hopkins County, Kentucky	ALL PROPERTY TRANSFERRED TO MINE NO. 21			
11	Mine No. 25 - Mary Moers - Vermilion County, Illinois	398.77	39.23	353,530	Active - Mining - Strip
	TOTAL - ACTIVE - MINING	28,091.03	7,628.59	56,759,439	
12	North Canton Field - Fulton County, Illinois	2,755.04	1,574.15	8,231,630	Active - Prospecting - Strip
13	Banner Field - Peoria & Fulton Counties, Illinois	1,790.35	1,508.21	5,690,387	Active - Prospecting - Strip
13	Kingston River Terminal - Peoria County, Illinois	(76.50)	-	-	Dock Site
14	Gayle Field - Perry County, Illinois	457.22	222.43	1,714,720	Active - Prospecting - Strip
15	Industry Field - McDonough County, Illinois	3,060.50	2,529.10	8,976,117	Active - Prospecting - Strip
16	Buffalo Creek No. 2 - Hopkins & Christian Counties, Kentucky	1,058.72	262.10	1,399,399	Active - Prospecting - Strip
	TOTAL - ACTIVE - PROSPECTING	8,631.83	6,156.29	26,080,213	
16					
16	South Buckheart Field - Fulton County, Illinois	160.00	103.22	344,842	Inactive - Isolated - Strip
16	LeFlore County, Oklahoma	1,000.00	502.90	2,301,872	Inactive - Strip
	TOTAL - INACTIVE - STRIP	1,160.00	606.12	2,646,714	
	GRAND TOTAL - STRIP RESERVES	37,882.86	14,471.00	85,486,366	

THE UNITED ELECTRIC COAL COMPANIES
LANDS & RESERVE COAL
AS OF JULY 31, 1959

PAGE NO.	DEEP RESERVES	ESTIMATED RESERVE COAL TOTAL ACRES	COAL ACRES	TONS	REMARKS
17	Mine No. 21 - Hopkins County, Kentucky	3,172.96	1,961.73	6,489,403	Inactive - Deep
18	Mine No. 11 - Fidelity - Perry County, Illinois	1,256.54	898.50	5,114,180	Inactive - Deep
19 & 20	Buffalo Creek No. 2 - Hopkins & Christian Counties, Kentucky	2,055.50	1,143.22	4,003,097	Inactive - Deep
21 & 22	Round Prairie Field - Perry County, Illinois	3,483.24	3,400.24	20,962,142	Inactive - Deep
	TOTAL - INACTIVE - DEEP	10,006.24	7,403.69	36,649,922	
23	Salt Fork Field - Vermilion County, Illinois	136.20	136.00	691,152	Inactive - Isolated - Deep
23	Harris Property - Vermilion County, Illinois	333.80	310.00	1,590,000	Inactive - Isolated - Deep
23	Sullivan Property - Vermilion County, Illinois	40.30	40.00	205,360	Inactive - Isolated - Deep
	TOTAL - INACTIVE - DEEP	489.80	486.00	2,486,512	
	GRAND TOTAL - DEEP RESERVES	10,496.04	7,889.69	39,136,434	
	TOTAL - STRIP RESERVES	37,882.36	14,471.00	85,426,366	
	TOTAL - DEEP RESERVES	10,496.04	7,889.69	39,136,434	
	GRAND TOTAL - RESERVES	48,380.90	22,360.69	124,562,800	

THE UNITED ELECTRIC COAL COMPANIES
LANDS & RESERVE COAL
AS OF JULY 31, 1961

PLAT NO.		TOTAL ACRES	ESTIMATED RESERVE COAL: COAL ACRES	ESTIMATED RESERVE COAL: TONS	STATUS
1 & 2	Mine No. 9 - Cuba - Fulton County, Illinois	5,806.60	663.73	5,729,668	Active - Mining - Strip
3, 4 & 5	Mine No. 11 - Fidelity - Perry County, Illinois	9,247.30	3,214.03	27,488,079	Active - Mining - Strip
6 & 7	Clinch Field - Fidelity - Perry County, Illinois	1,340.16	210.51	1,921,936	Active - Mining - Strip
8, 9 & 10	Mine No. 17 - Buckheart - Fulton County, Illinois	10,678.53	3,171.10	20,676,351	Active - Mining - Strip
11	Mine No. 19 - Buffalo Creek - Hopkins County, Kentucky	1,192.05	59.33	208,943	Active - Mining - Strip
12	Mine No. 25 - [illegible] - Vermilion County, Illinois	378.77	63.19	515,224	Active - Mining - Strip
	TOTAL - ACTIVE - MINING	28,640.46	7,573.10	55,590,141	
13	North Canton Field - Fulton County, Illinois	2,265.04	1,574.15	8,231,630	Active - Prospecting - Strip
14	Glasford-Canton Field - Peoria & Fulton Cos., Ill.	1,207.06	1,118.[illegible]	4,334,000	Active - Prospecting - Strip
14	Kingston River Terminal - Peoria County, Illinois	(76.20)	-	-	Dock Site
15	Coyle Field - Perry County, Illinois	454.02	222.43	1,714,730	Active - Prospecting - Strip
16	Industry Field - McDonough County, Illinois	3,060.70	2,529.10	8,776,317	Active - Prospecting - Strip
17	Buffalo Creek #2 - Hopkins & Christian Cos., Kentucky	1,328.71	465.96	2,465,463	Active - Prospecting - Strip
	TOTAL - ACTIVE - PROSPECTING	8,410.33	5,910.60	25,732,920	

THE UNITED ELECTRIC COAL COMPANIES
LANDS & RESERVE COAL
AS OF JULY 31, 1958

PAGE NO.		TOTAL ACRES	ESTIMATED RESERVE COAL: COAL ACRES	ESTIMATED RESERVE COAL: TONS	REMARKS
15	Leflore County, Oklahoma	1,020.00	582.90	2,301,872	Inactive - Strip
18	Mine No. 21 - Hopkins County, Kentucky	1,970.11	1,931.10	6,363,079	Inactive - Deep
18	Buffalo Creek No. 8 - Hopkins & Christian Cos. Ky.	2,327.97	1,231.91	4,371,209	Inactive - Deep
18	Deep Coal Reserve Mine No. 11 - Perry County, Ill.	1,376.54	898.50	5,114,160	Inactive - Deep
	TOTAL - INACTIVE - DEEP	5,674.62	4,061.51	15,873,453	
18	South Dashboard Field - Fulton County, Illinois	140.00	103.22	744,842	Inactive - Isolated - Strip
19	Hunsie Property - Vermilion County, Illinois	313.00	310.00	1,550,000	Inactive - Isolated - Deep
19	Smalley Property - Vermilion County, Illinois	40.00	40.00	215,250	Inactive - Isolated - Deep
	TOTAL - INACTIVE - ISOLATED - DEEP	353.00	350.00	1,775,110	
	TOTAL - ACTIVE RESERVES	37,058.81	13,468.40	82,343,011	
	TOTAL - INACTIVE RESERVES	7,188.42	5,097.63	20,315,592	
	GRAND TOTAL - RESERVES	44,247.23	18,526.11	102,658,603	

(C) CHANGES IN RESERVE TONNAGE 1958 - 1969

MEMO

CHANGES IN STRIP RESERVE TONNAGE DURING 1969

MINE NO. 9

Mined Out	(805,608)
Estimated Adjustment	(91,200)
Yield Loss	(55,538)
New Lands	7,727
Net Change	(944,619)

MINE NO. 11

Mined Out	(1,146,041)
Estimate Change	(460,046)
Yield Gain, Present Pit	111,734
New Lands	2,059,337
Net Change	564,984

CLINCH PIT

Mined Out	(687,909)
Yield Gain	29,585
Estimated Adjustment	17,741
Net Change	(640,583)

MINE NO. 17 (NORTH)

Mined Out	(957,832)
Estimated Adjustment	-
Yield Gain	29,023
Net Change	(928,809)

MINE NO. 17 (SOUTH)

Mined Out	(1,304,530)
Estimated Adjustment	508,356
Yield Gain	142,638
New Leases	-
Net Change	(653,536)

MINE NO. 27

Mined Out	(685,932)
Estimated Adjustment	(242,976)
Yield Loss	(46,092)
Net Change	(975,000)

MEMO

CHANGES IN STRIP RESERVE TONNAGE DURING 1968

MINE NO. 9

Mined Out	....	(738,055)
Estimated Adjustment	....	(7,919)
Yield Loss	....	(28,084)
New Lands	....	287,505
Estimated Change	....	(744,849)
Yield Change	....	(337,373)
Net Change	....	(1,568,775)

MINE NO. 11

Mined Out	....	(1,709,357)
Estimated Adjustment	....	(91,624)
Yield Gain	....	57,521
New Lands	....	348,816
Net Change	....	(1,394,644)

CLINCH PIT

Mined Out	....	(134,736)
Yield Loss	....	(5,881)
Net Change	....	(140,617)

MINE NO. 17 (NORTH)

Mined Out	....	(872,715)
Estimated Adjustment	....	(48,891)
Yield Gain	....	43,179
Net Change	....	(878,427)

MINE NO. 17 (SOUTH)

Mined Out	....	(1,129,631)
Estimated Adjustment	....	372,330
Yield Gain	....	74,487
New Leases	....	236,387
Net Change	....	(446,427)

MINE NO. 27

Mined Out	....	(675,217)
Estimated Adjustment	....	(56,411)
Yield Loss	....	(76,673)
Net Change	....	(808,301)

MEMO: Changes in Strip Reserve Tonnage During 1967

MINE NO. 9

Mined Out..................................	(974,347)
Estimated Adjustment......................	21,179
Yield Loss................................	(42,294)
New Lands.................................	223,403
Net Change................................	(772,059)

MINE NO. 11

Mined Out..................................	(2,031,157)
Estimated Adjustment......................	(29,010)
Yield Gain................................	104,590
New Lands.................................	60,204
Net Change................................	(1,895,373)

MINE NO. 17 (North)

Mined Out..................................	(987,301)
Estimated Adjustment......................	(20,895)
Yield Gain................................	15,024
Lease Expired (Floyd Shelby et al).....	(53,635)
Net Change................................	(1,046,807)

MINE NO. 17 (South)

Mined Out..................................	(916,633)
Estimated Adjustment......................	71,604
Yield Gain................................	64,914
Net Change................................	(780,115)

MINE NO. 27

Mined Out..................................	(834,021)
Estimated Adjustment......................	(42,839)
Yield Loss................................	(132,307)
Net Change................................	(1,009,167)

BUFFALO CREEK NO. 2

Reserves on January 1, 1967............	1,166,570
In Process of being sold...............	(1,166,570)
	- 0 -

MEMO: Changes in Deep Reserve Tonnage During 1967

BUFFALO CREEK NO. 2

Reserves on January 1, 1967....	3,223,378
In Process of being sold.......	(3,223,379

ROUND PRAIRIE FIELD

Estimate Adjustment............	(164,226)
New Lands......................	869,406
Net Change.....................	705,180

ROUND PRAIRIE FIELD (Isolated)

Estimate Adjustment............	(100,180)
Net Change.....................	(100,180)

MEMO: Changes in Strip Reserve Tonnage During 1966

MINE NO. 9

Mined Out..............................	(931,826)
Estimate Adjustment....................	23,971
Yield Loss.............................	(25,673)
New Lands..............................	109,180
Net Change.............................	(824,348)

MINE NO. 11

Mined Out..............................	(2,080,251)
Estimate Adjustment....................	(647,251)
Yield Gain.............................	94,347
New Lands..............................	1,351,245
Net Change.............................	(1,281,910)

MINE NO. 17 (North)

Mined Out..............................	(2,033,621)
Estimate Adjustment....................	340,837
Yield Gain.............................	97,609
Net Change.............................	(1,595,175)

MINE NO. 17 (South)

New Lands..............................	941,836
Net Change.............................	941,836

MINE NO. 27

Mined Out..............................	(809,240)
Yield Loss.............................	(134,226)
Net Change.............................	(943,466)

BUFFALO CREEK NO. 2

Lease Expired..........................	(232,820)
Net Change.............................	(232,820)

MEMO: Changes in Deep Reserve Tonnage During 1966

BUFFALO CREEK NO. 2

Lease Not Renewed..........................	(105,479)
Net Change.................................	(105,479)

MEMO: Changes in Strip Reserve Tonnage During 1965

MINE NO. 9

Mined Out	(840,705)
Estimate Adjustment	75,600
Yield Loss	(66,549)
New Lands	4,113,345
Net Change	3,281,691

MINE NO. 11

Mined Out	(1,825,255)
Estimate Adjustment	(591,629)
Yield Loss	(285,576)
New Lands	9,278
Net Change	(2,693,182)

MINE NO. 17 (North)

Mined Out	(1,992,089)
Estimate Adjustment	(251,908)
Yield Gain	152,293
New Lands	355,407
Net Change	(1,736,297)

MINE NO. 17 (South)

New Lands	1,775,380
Net Change	1,775,380

MINE NO. 25

Mined Out	(20,163)
Estimate Adjustment	948
Net Change	(19,215)

MINE NO. 27

Mined Out	(670,429)
Yield Loss	(15,361)
New Lands	1,439,634
Net Change	753,844

Changes in Strip Reserve Tonnage During 1965 (Cont')

NORTH CANTON FIELD

Leased to Truax-Traer..................	(10,177,773)
Leased from Truax-Traer................	4,014,785
Net Change.............................	(6,162,988)

HAYDEN FIELD, COLORADO

New Lands..............................	12,522,000
Net Change.............................	12,522,000

Changes in Deep Reserve Tonnage During 1965

BUFFALO CREEK NO. 2

Lease not renewed......................	(464,640)
Net Change.............................	(464,640)

ROUND PRAIRIE FIELD

New Lands..............................	6,507,944
Estimate Adjustment....................	(338,769)
Net Change.............................	6,169,175

MEMO: Changes in Strip Reserve Tonnage from 8/1/64 to 12/31/64

MINE NO. 9

Mined Out	(407,422)
Estimate Adjustment	(12,119)
Yield Gain	7,676
Net Change	(411,865)

MINE NO. 11

Mined Out	(816,707)
Estimate Adjustment	(15,364)
Yield Gain	5,000
New Lands	155,224
Net Change	(671,847)

MINE NO. 17 (North)

Mined Out	(901,959)
Estimate Adjustment	(140,278)
Yield Gain	100,000
New Lands	122,390
Net Change	(819,847)

MINE NO. 25

Mined Out	(87,154)
Estimate Adjustment	11,189
Net Change	(75,965)

MINE NO. 27

Mined Out	(267,310)
Yield Loss	(28,250)
New Lands	220,500
Net Change	(75,060)

Changes in Deep Reserve Tonnage from 8/1/64 to 12/31/64

ROUND PRAIRIE FIELD

New Lands	232,320
Net Change	232,320

MEMO: Changes in Strip Reserve Tonnage During Fiscal Year 1964

MINE NO. 9

Mined Out	(840,871)
Yield Loss	(23,569)
Estimate Adjustment	(30,949)
Measurement Adjustment	138,045
New Lands	1,400,373
Reactivated Reserves	354,000
Net Change	997,029

MINE NO. 11

Mined Out	(1,892,040)
Yield Loss	(33,098)
Estimate Adjustment	(67,591)
Measurement Adjustment	40,774
New Lands	1,403,971
Net Change	(547,984)

MINE NO. 17 (North)

Mined Out	(1,848,954)
Yield Gain	98,212
Estimate Adjustment	207,544
New Lands	594,766
Net Change	(948,432)

MINE NO. 17 (South)

New Lands	1,113,200
Net Change	1,113,200
Net Change Mine #17 North & South	164,768

MINE NO. 25

Mined Out	(263,937)
Estimate Adjustment	(2,404)
New Lands	16,000
Net Change	(250,341)

Changes in Strip Reserve Tonnage (Cont'd)

MINE NO. 27

Mined Out..................................	(717,084)
Yield Loss.................................	(52,060)
Yield Gain.................................	6,683
New Lands..................................	1,149,232
Net Change.................................	386,771

NORTH CANTON FIELD

New Lands..................................	996,600
Net Change.................................	996,600

INDUSTRY FIELD

New Lands..................................	600,000
Net Change.................................	600,000

Changes in Deep Reserve Tonnages During Fiscal Year 1964

ROUND PRAIRIE FIELD

New Lands..................................	13,293,081
Net Change.................................	13,293,081

MEMO: Changes in Strip Reserve Tonnage During Fiscal Year 1963

MINE NO. 9

Mined..................................	(804,920)
Yield Loss..............................	(62,311)
Yield Gain..............................	64,332
Net Change..............................	(802,899)

MINE NO. 11

Mined..................................	(1,934,447)
New Lands..............................	3,218,264
Yield Loss..............................	(61,850)
Yield Gain..............................	78,847
Estimate Adjustment....................	(1,647)
Adjustment in Measurement.............	17,504
Net Change..............................	1,316,671

MINE NO. 17 (North)

Mined..................................	(1,339,455)
New Lands..............................	324,219
Yield Gain..............................	114,578
Estimate Adjustment....................	(11,183)
Net Change..............................	(911,841)

MINE NO. 17 (South)

New Lands..............................	559,000
Net Change..............................	559,000
Net Change Mine #17 North & South	(352,841)

MINE NO. 25

Mined..................................	(265,583)
Yield Loss..............................	(17,031)
Net Change..............................	(282,614)

MINE NO. 27

Mined..................................	(602,158)
New Lands..............................	579,300
Yield Loss..............................	(27,920)
Estimate Adjustment....................	(172,174)
Net Change..............................	(222,952)

Changes in Strip Reserve Tonnage Cont'd

NORTH CANTON FIELD

New Lands................................	4,761,855
Estimate Adjustment......................	69,960
Net Change...............................	4,831,815

INDUSTRY FIELD

New Lands................................	251,440
Net Change...............................	251,440

Changes in Deep Reserve Tonnages During Fiscal Year 1963

BUFFALO CREEK NO. 2

Lease Dropped............................	(290,400)
Net Change...............................	(290,400)

ROUND PRAIRIE FIELD

Change to Round Prairie Deep Coal - Isolated..................	(545,981)
Net Change...............................	(545,981)

MEMO: Changes in Strip Reserve Tonnage During Fiscal Year 1952

MINE NO. 9

Mined	819,313
Yield Loss	958
Yield Gain	47,612
Net Change	772,659

MINE NO. 11

Mined	1,662,957
Yield Loss	2,004
Yield Gain	34,389
Estimate Adjustment	4,298
Adjustment in Measurement	7,728
Net Change	1,626,142

MINE NO. 17 (North)

Mined	1,220,592
New Lands	525,577
Yield Loss	2,321
Yield Gain	27,500
Estimate Adjustment	6,608
Net Change	663,728

MINE NO.17 (South)

New Lands	2,888,892
Net Change	2,888,892

Net Chenge Mine No. 17 North & South 2,225,164

MINE NO. 25

Mined	250,394
Estimate Adjustment	12,429
Yield Loss	618
Estimate Adjustment	68,053
Yield Gain	19,844
New Lands	632,179
Net Change	456,635

MINE NO. 27

Mined	707,850
Yield Gain	37,776
New Lands	138,000
Net Change	532,074

Changes in Strip Reserve Tonnage (Cont'd)

NORTH CANTON FIELD

New Lands----------------------------------	2,413,409

SALT FORK FIELD

Cancelled - C. W. Dukes----------------	691,152
Net Change--------------------------------	691,152
Grand Total Salt Fork------------------	- 0 -

MEMO: Changes in Strip Reserve Tonnage During Fiscal Year 1961

MINE NO. 9

Mined	864,659
Yield Loss	19,756
Net Change	884,415

MINE NO. 11

Mined	1,447,814
New Lands	4,066
Estimate Adjustment	314,048
Yield Loss	1,044
Net Change	1,758,840

MINE NO. 17

Mined	1,306,751
New Lands	144,000
Estimate Adjustment	5,120
Yield Gain	13,450
Net Change	1,144,181

MINE NO. 25

Mined	211,773
New Lands	291,457
Estimate Adjustment	53,516
Net Change	133,200

MINE NO. 27

Mined	516,570
New Lands	671,500
Estimate Adjustment	539,857
Yield Loss	2,194
Net Change	417,131

NORTH CANTON FIELD

New Lands	524,100

INDUSTRY FIELD

New Lands	169,300

MEMO: Changes in Deep Reserve Tonnage During Fiscal Year 1961

ROUND PRAIRIE FIELD

New Lands	1,974,720

MEMO: Changes in Strip Reserve Tonnage During Fiscal Year 1960

MINE NO. 9

Mined	950,838
Estimate Adjustment	3,539
Yield Loss	30,571
Net Change	984,948

MINE NO. 11

Mined	1,012,262
New Lands	1,662,320
Estimate Adjustment	461,388
Yield Loss	33,966
Net Change	94,706

MINE NO. 11 (CLINCH)

Mined	226,056
Yield Gain	12,299
Estimate Adjustment	23,889
Net Change	189,858

MINE NO. 17

Mined	1,320,996
Estimate Adjustment	352,361
Yield Loss	43,815
Net Change	1,012,450

MINE NO. 25

Mined	327,635
Yield Gain	42,405
Net Change	285,230

MINE NO. 27

Mined	23,629
Estimate Adjustment	649,379
New Lands	3,841,878
Net Change	3,168,870

2,3

INDUSTRY FIELD

New Lands	2,553,600

NORTH CANTON FIELD

New Lands	521,400

MEMO: Changes in Deep Reserve Tonnage During Fiscal Year 1960

ROUND PRAIRIE FIELD
New Lands-- 1,290,700

MINE NO. 21
Sold--- 6,489,403

MEMO: Changes in Strip Reserve Tonnage During Fiscal Year 1959

MINE NO. 9

Mined	842,831
Yield Loss	26,913
Estimate Correction	21,363
Net Change	835,481

MINE NO. 11

Mined	34,316
New Lands	805,190
Net Change	770,874

MINE NO. 11 (CLINCH)

Mined	1,128,669
Estimate Correction	31,371
New Lands	181,220
Yield Gain	30,452
Net Change	950,868

MINE NO. 17

Mined	1,251,453
New Lands	3,056,000
Lease Dropped	27,700
Estimate Correction	70,432
Yield Loss	71,005
Net Change	1,635,410

101755

MINE NO. 19

Mined	130,229
Transferred to Mine #21 Deep Reserves	93,714
Net Change	223,943

MINE NO. 25

Mined	303,116
Estimate Correction	86,422
Net Change	221,694

BANNER FIELD

New Lands	1,439,000
Estimate Correction	74,643
Net Change	1,364,357

BUFFALO CREEK MINE NO. 2

Lease Expired	1,097,064

Young

NEW: Changes in Deep Reserve Tonnage During Fiscal Year 1959

BUFFALO CREEK MINE #2	
Lease Expired	391,159
Estimate Correction	96,152
Net Change	287,342
MINE #21	
Transferred from Mine #19 Strip Reserve	1 101,324
ROUND PRAIRIE FIELD	
New Lands	20,962,342
SALT FORK FIELD	
New Lands	691,152

MEMO: Changes in Reserve Tonnage During Fiscal Year 1958

MINE NO. 9

Mined	794,666
Estimate Correction	43,046
Yield Loss	20,915
Little Sister Trade	607,607
Net Change	251,020

MINE NO. 11

Quit claim 5 acres to Sacred Heart Catholic Church	44,120
Union Colliery Purchase	4,476,414
Re-estimate of adjacent property to the Union Collieries purchase	1,323,322
Net Change	5,755,616

MINE NO. 11 (CLINCH)

Mined	1,152,822
New Lands	328,518
Estimate Correction	61,704
Yield Gain	37,901
Net Change	724,699

MINE NO. 17

Mined	1,099,162
Dropped Lease	13,340
Estimate Correction	67,659
Yield Loss	13,304
New Lands	1,764,700
Net Change	571,235

MINE NO. 19

Mined	247,079
Transferred from deep reserves Mine #21	221,958
Yield Gain	10,701
Net Change	14,420

MINE NO. 25

Mined	303,519
Estimate Correction	75,710
Yield Loss	1,736
Net Change	380,965

GLASFORD-DANNER FIELD

New Lands	145,824

BUFFALO CREEK #2 FIELD

New Lands	2,496,463

MINE #21

Transferred to #19 strip reserves	190,276

Changes in Reserve Tonnage (Cont'd)

LEASE TO UNION COLLIERY (Inactive Deep)

Lease discontinued - Included in Mine #11 Strip Reserves---------------------------------- 883,084

DEEP COAL RESERVES - MINE NO. 11

Union Colliery Purchase---------------------------5,114,180

DEEP COAL RESERVE - BUFFALO CREEK #2 (Inactive Deep)

New Lands---4,371,209

(D) POSSIBLE ACQUISITIONS

THE UNITED ELECTRIC COAL COMPANIES
Possible Acquisitions
Cuba - Mine #9
Fulton County, Illinois

Name	Acres	Possible Coal Acres	Possible Tons	Remarks
ringe Tracts	308	50	300,000	Acquisition Doubtful. Coal in Islands
Total	308	50	300,000	

his mine has operated over 40 years, and is bounded by the City of uba, outcrop of the No. 5 and No. 6 coals on the west and south, orth and east by old works of other companies.

/1/70

THE UNITED ELECTRIC COAL COMPANIES
Possible Acquisitions
Fidelity - Mine #11
Perry County, Illinois

Name	Acres	Possible Coal Acres	Possible Tons	Remarks
Northwest Field				
Walker	120	60	Less than 500,000	Negotiating
Fringe Tracts	-	-	250,000	Negotiating
Total	120	60	Less than 750,000	
Kathleen or Southwest Area				
Harsha	40	20	160,000	Cannot Acquire to Date
Eisenhauer	20	10	80,000	Negotiating
Sutter	80	60	500,000	Negotiating
Fringe Tracts	-	-	300,000	Negotiating
Total	140	90	1,040,000	

Mine was started in 1929. Land acquisition in 1926, and only hard to buy reserves remain. Mine is bounded on the north by mined out ground, on the east by Du Quoin and old works, south by old works and cropline of No. 6 coal, on the west by cropline and cutout several miles wide, west of which the coal has been removed. As far as is known there is no minable coal in the No. 6 or any other vein, deep or strip, that can be added.

3/1/70

THE UNITED ELECTRIC COAL COMPANIES
Possible Acquisitions
Buckheart - Mine #17
Fulton County, Illinois

Name	Acres	Possible Coal Acres	Possible Tons	Remarks
Bull	80	75	500,000	In Estate - Cannot Buy at Present
McLouth	160	80	500,000	Extremely doubtful
Total	240	155	1,000,000	

The mine has operated since 1937. Bounded on the north by old works, unminable coal and cutout of coal, on the east by the cropline of No. 5 coal, south by old works and end of coal field, and on the west by large cutout and cropline of No. 5 coal.

3/1/70

THE UNITED ELECTRIC COAL COMPANIES
Possible Acquisitions
Banner - Mine #27
Peoria & Fulton Counties, Illinois

Name	Acres	Possible Coal Acres	Possible Tons	Remarks
Fuller	30	30	100,000	Not drilled.

Mine No. 27 lies in the river bottom and is surrounded by natural boundaries. North by a range of hills containing little coal recoverable by stripping or underground mining, east by a narrow river bottom and levee, south by the Illinois River and west by Rice Lake. 462 acres north and northeast of the field has been drilled and dropped.

3/1/70

THE UNITED ELECTRIC COAL COMPANIES
Possible Acquisitions
North Canton

Fringe Areas - When the field is opened, we may option and drill several farms adjoining the cropline, but less than 500,000 tons of additional reserves, if any, are expected. Field is limited to No. 6 coal, practically all of which has been delineated, plus a small amount of No. 5 in valleys.

3/1/70

DEFENDANT'S EXHIBIT NO. 60-D

THE UNITED ELECTRIC COAL COMPANIES

Possible Reserve Acquisitions at Existing Mines

I. Summary Table

Name of Mine	Reserves Dec. 31, 1969	Potential Acquisitions Tons of Coal March 1, 1970
CUBA #9	1,206,260	300,000
BUCKHEART NORTH CANTON	27,379,963	1,500,000
BANNER	5,081,691	100,000
FIDELITY	18,365,390	1,790,000
TOTAL:	52,033,304	3,690,000

3/1/70

II. Explanation of Above Table

A. Cuba Mine #9 - Fulton County, Illinois

Name	Acres	Possible Coal Acres	Possible Tons	Remarks
Fringe Tracts	308	50	300,000	Acquisition Doubtful. Coal in Islands.
Total	308	50	300,000	

This mine has operated over 40 years, and is bounded by the City of Cuba, outcrop of the No. 5 and No. 6 coals on the west and south, north and east by old works of other companies.

B. Buckheart Mine #17 - Fulton County, Illinois

Name	Acres	Possible Coal Acres	Possible Tons	Remarks
Bull	80	75	500,000	In Estate. Cannot Buy at Present.
McLouth	160	80	500,000	Extremely doubtful.
Total	240	155	1,000,000	

The mine has operated since 1937. Bounded on the north by old works, unminable coal and cutout of coal, on the east by the cropline of No. 5 coal, south by old works and end of coal field, and on the west by large cutout and cropline of No. 5 coal.

North Canton

Fringe Areas - When the field is opened, we may option and drill several farms adjoining the cropline, but less than 500,000 tons of additional reserves, if any, are expected. Field is limited to No. 6 coal, practically all of which has been delineated, plus a small amount of No. 5 in valleys.

3/1/70

C. Banner Mine #27 - Peoria & Fulton Counties, Illinois

Name	Acres	Possible Coal Acres	Possible Tons	Remarks
Fuller	30	30	100,000	Not drilled.
Total	30	30	100,000	

Mine No. 27 lies in the river bottom and is surrounded by natural boundaries. North by a range of hills containing little coal recoverable by stripping or underground mining, east by a narrow river bottom and levee, south by the Illinois River and west by Rice Lake. 462 acres north and northeast of the field has been drilled and dropped.

3/1/70

D. Fidelity Mine #11 - Perry County, Illinois

Name	Acres	Possible Coal Acres	Possible Tons	Remarks
Northwest Field				
Walker	120	60	Less than 500,000	Negotiating
Fringe Tracts	-	-	250,000	Negotiating
Total	120	60	Less than 750,000	
Kathleen or Southwest Area				
Harsha	40	20	160,000	Cannot Acquire to Date
Eisenhauer	20	10	80,000	Negotiating
Sutter	80	60	500,000	Negotiating
Fringe Tracts	-	-	300,000	Negotiating
Total	140	90	1,040,000	

Mine was started in 1929. Land acquisition in 1926, and only hard to buy reserves remain. Mine is bounded on the north by mined out ground, on the east by Du Quoin and old works, south by old works and cropline of No. 6 coal, on the west by cropline and cutout several miles wide, west of which the coal has been removed. As far as is known there is no minable coal in the No. 6 or any other vein, deep or strip, that can be added.

3/1/70

The Following

COAL RESERVES OF LISTED COMPANIES IN
ILLINOIS, INDIANA AND WESTERN KENTUCKY - 1968

	Company	Tons	Percentage of Total Tons Shown
1.	Peabody Coal Company	3,780,898,842	30.05%
2.	Humble Oil Company	3,250,000,000*	25.83
3.	Island Creek Coal Company	1,162,878,000	9.24
4.	Consolidation Coal Company	963,640,000	7.66
5.	Old Ben Coal Corporation	796,000,000	6.33
6.	Ayrshire Collieries Corp.	767,168,071	6.10
7.	Bell & Zoller Coal Company	550,000,000	4.37
8.	Freeman Coal Mining Corp.	483,687,408	3.84
9.	Pittsburg & Midway Coal Mining Co.	278,205,000	2.21
10.	Southwestern Illinois Coal Corp.	170,800,000	1.36
11.	The United Electric Coal Companies	121,851,616	.97
12.	Sahara Coal Company, Inc.	90,000,000	.72
13.	Morris Brothers Company	32,000,000	.25
14.	Venedy Coal Company, Inc.	27,300,000	.22
15.	Webster County Coal Corp.	25,000,000	.20
16.	Green Coal Company	20,000,000	.16
17.	Gibraltar Coal Corporation	19,091,904	.15
18.	Rialto Coal Company, Inc.	13,200,000	.10
19.	Pyro Mining Company	6,500,000	.05
20.	Black Tam Mining Company	6,000,000	.05
21.	Kirkpatrick Mining Company	5,116,000	.04
22.	Blue Bird Coal Company	2,792,500	.02
23.	R. S. & K. Coal Corporation	2,000,000	.01
24.	Russell Badgett, Jr. Coal Co.	1,200,000	.**
25.	Weirs Creek Company	1,200,000	.**
26.	Wright Coal Company	1,140,000	.**
27.	Belle Valley Coal Company, Inc.	1,097,712	.**
28.	Burge Coal Company, Inc.	550,000	.**
29.	V-Day Coal Company	500,000	.**
30.	Sherwood-Templeton Coal Co., Inc.	472,000	.**
31.	Harrisburg Coal Company	320,000	.**
32.	Barbara Kay Coal, Inc.	300,000	.**
33.	Parton Coal Company, Inc.	240,000	.**
34.	Decola Coal Company	200,000	.**
35.	Weskol Mining Company	200,000	.**
36.	B B Mining Company	30,000	.**
37.	Houston Coal Company	25,000	.**
	TOTAL	12,581,604,053	100.00%

Source: Form 250, Subpoena Questionnaire

* Source: Letter of February 19, 1968 from Humble Oil & Refining Company to Department of Justice and assumed recovery of 5,000 tons per acre. See also Respondent's Exhibit No. 184 A-F received in evidence in Federal Trade Commission Docket 8765, in the matter of Kennecott Copper Corporation, and stipulated testimony of George H. Shipley.

** Less than .01 percent.

DEFENDANTS' EXHIBIT 62

TYPES OF COAL RESERVES HELD BY LISTED COMPANIES* IN

ILLINOIS, INDIANA AND WESTERN KENTUCKY - 1968

	Dedicated to Existing Mines	Other Reserves	Total
Strip	1,140,661,140	646,062,584	1,786,723,724
Deep	1,132,526,758	6,412,353,571	7,544,880,329
	2,273,187,898	7,058,416,155	9,331,604,053

* See Defendants' Exhibit 61 . Tonnages for Humble Oil Company (3,250,000,000) not included.

SOURCE: Form 250, Subpoena Questionnaire.

REFERENCE: Report of Paul Weir Company, Weir Deposition Exhibit 2, pp. 23-24.

THE UNITED ELECTRIC COAL COMPANIES

COMMITTED AND UNCOMMITTED RESERVES - BY MINES

Mine	Consumer	Expiration Date	Maximum Annual Tons Committed (000)	Total Tons Committed 1/1/69 To Expiration (000)	Strippable Reserves As Of 1/1/69 (000)	Uncommitted Tons (000)	Remarks
BANNER							
	1. Marquette Cement	5-31-75	300 1/	1,925			Current - 5 Year Renewal Option*
	2. Union Carbide Corp. Linde Div.	4-30-71	90 1/	210			Current
	3. Central Ill. Public Service	9-30-79	200	2,000			Current
	TOTAL BANNER			4,135	6,057	1,922	
CUBA-BUCKHEART							
	1. Commonwealth Edison	12-31-70	2,250	4,500			Current
	2. Central Ill. Light Co.	12-31-91	1,100	20,900			Effective 1-1-73
	3. Central Ill. Light Co.	12-31-72	610 2/	2,440			Current
	4. Corn Products Co.	12-31-71	225 1/	675			Current
	5. Foote Minerals-Kemco Div.	3-31-72	50	160			Current
	TOTAL CUBA-BUCKHEART			28,675	31,113 3/	2,438	
FIDELITY							
	1. Northern States Power	3-14-70	480	480			Current - Renewal Being Negotiated **
	2. Union Electric	4-30-71	375	875			Current - Renewal Being Negotiated **
	3. Wisconsin Power & Light	12-31-78	180 1/	1,800			Current
	4. Interstate Power	12-31-75	100	700			Current - 10 Year Renewal Option *
	5. Iowa Public Service	9-30-72	100	375			Current
	6. Dairyland Power Coop.	12-31-80	90 2/	1,060			Current
	7. City of Fairfield	4-30-71	25 1/	60			Current
	8. Jn. Deere DuBuque	3-31-78	20	35			Current
	9. Jn. Deere Waterloo	3-31-70	30	40			Current
	Tonnage Committed to Current Negotiations			10,700**			No. States P.; Un. Elec., WIPSCO
	TOTAL FIDELITY			16,125	18,441	2,326	
	TOTAL ALL MINES			48,935	55,611	6,686	
	Tonnage Subject to Buyers' Unexercised Renewal Options					2,500*	
						9,186	

1/ Based on current plant requirements or portion thereof
2/ Annual average of escalating commitments
3/ Includes North Canton

SOURCE: Records of the Company

9/9/69

DEFENDANT'S EXHIBIT 63

DEFENDANT'S EXHIBIT 66

WISCONSIN ELECTRIC POWER COMPANY
231 WEST MICHIGAN STREET
MILWAUKEE, WISCONSIN 53201

May 21, 1968

Mr. John T. Cusack
Attorney, Midwest Office
Antitrust Division
Department of Justice
Room 2634, United States Courthouse
Chicago, Illinois 60604

60-0-37-920
DEPARTMENT OF JUSTICE
MAY 22 1968
DIVISION OF RECORDS
Cusack

Re: United States v. General Dynamics Corporation et al., Civil Action No. 67 C 1632 (N.D. Ill.)
60-0-37-920

Dear Mr. Cusack:

This is in reply to your letter of April 9 addressed to Mr. C. F. John requesting information in regard to the above referenced civil action.

The information requested in paragraphs 1 and 2 of your letter is detailed in Tables I and II attached. All coal purchased for the following generating stations for the years 1964 through 1967 was delivered to storage docks by lake vessels during the navigation season for Lake Michigan, which normally extends from April 1 to December 1 each year:

Oak Creek Power Plant
Port Washington Power Plant
Commerce Street Power Plant
East Wells Street Power Plant

This coal was consumed approximately from mid-April of the year in which it was delivered to mid-April of the following year. Coal purchased for use at our Lakeside Power Plant for the same years was consumed during the calendar year in which it was purchased. The footnotes of Tables I and II explain the variance in the period coal was purchased and consumed.

In response to your paragraph 3, during the referenced period facilities for generating electricity by utilizing oil and gas were available at the Commerce Street Power Plant. Details in regard to gas and oil consumption are given in Table III attached. Boiler #25 of this plant is the only unit so equipped and was equipped to burn gas or oil exclusively since November, 1964. This unit has a capability of 22,000 kw

Mr. John T. Cusack - Page 2. 5/21/1968.

when supplying 230,000 lbs. per hour of steam for our heating utility. The footnotes to Table III explain the seasonal usage of gas and oil and the portion of each used for steam production at this plant.

In response to paragraph 4, no facilities were available for generating electricity by nuclear energy through the years 1964 through 1967.

Facilities for generating electricity from other sources as requested in paragraph 5 are limited to hydroelectric and diesel plants of Wisconsin Michigan Power Company, a wholly owned subsidiary of Wisconsin Electric Power Company. The information which you requested regarding these facilities is given in Table IV attached.

Data in response to paragraph 6 of your letter are not available.

You will note from the several documents attached that the majority of our coal is derived from mines in Illinois and western Kentucky. We believe that the acquisition by General Dynamics Corporation of the United Electric Coal Companies made it possible for the latter companies to have available financial resources for the development of mining properties and to increase the availability of coal sources from these regions.

You may wish to correct your records to indicate that Mr. C. F. John retired as Vice President in Charge of Power on December 31, 1965.

Very truly yours,

Robert H. Gorske

Robert H. Gorske General Counsel

Attach.

DEFENDANT'S EXHIBIT 67

COST FOR GAS FUEL VS. COAL FUEL FOR PEKIN BOILER HOUSE

During 1967, natural gas was used in the plant for various process uses while coal was used exclusively in the boiler house.

To determine the effect of burning all gas in the boiler house instead of coal, data from monthly boiler efficiency calculations was taken. The total heat required in coal fuel during grind and no grind periods and the average boiler efficiency was tabulated. This heat was converted into equivalent gas heat on the basis of gas boilers operating at 83% efficiency.

The increased amount of gas used on the boilers is all used at the lowest contract rate. There is no separate demand charge for gas, any demand rate consideration is included in the contract rates.

The following data summarizes the above calculations for each month during 1967.

Cost of gas fuel for boilers to supply an equivalent amount of heat as from coal for the year 1967 (based on gas, incremental rate, grind, and no grind)	**$2,036,800 per year**
Actual cost of coal burned in boiler house during year 1967 (grind and no grind)	**$1,191,909 per year**
Additional cost of fuel to operate boiler house on gas instead of coal (based on incremental gas rate, grind and no grind)	**$ 844,891 per year**

DEF 2/12/68

COMPANY LETTER

Moffet Technical Center
Argo, Illinois
February 13, 1968

TO: R. Meadowcroft

FROM: D. F. Franzen

SUBJECT: *Gas Firing In Boiler Houses at Argo and Pekin*

The Purchasing Department and the Pekin Plant have assured me, through their contacts with the gas companies, that sufficient gas is available to convert the steam generating facilities at Argo and Pekin from burning coal to gas.

The additional cost of fuel to operate the boiler houses on gas instead of coal, based on incremental gas cost and for the grind and no grind period of 1967 is

Argo, $984,000 per year

Pekin, $845,000 per year

DFF:pld

COMPANY LETTER

Moffet Technical Center
Argo, Illinois
February 23, 1968

TO: R. Meadowcroft

FROM: D. F. Franzen

FILE: Air Pollution

SUBJECT: *All Gas Firing for Boilers, Argo and Pekin*

In my letter of February 23 on this subject, I should have included the additional expense of about $50,000 per boiler for combustion controls at both the Argo and Pekin Plants.

	Total Cost of Combustion Control
Pekin—Boilers "A", "B", and "C" at $50,000	$150,000
Argo—Boilers 1, 2, and 3 at $50,000	150,000

DFF:pld

COMPANY LETTER

Moffet Technical Center
Argo, Illinois
February 23, 1968

TO: R. Meadowcroft

FROM: D. F. Franzen

FILE: Air Pollution

SUBJECT: *Gas Vs. Coal for Entire Pekin Boiler House*

My letter to you, dated February 13, 1968, indicated the additional cost that would have been entailed for the year 1967, if the Pekin Plant had burned all gas instead of coal was $845,000 per year.

Estimated operating savings which would be achieved if all coal burning were eliminated are:

Labor-coal and ash handling	$ 85,000 per year
Maintenance on coal unloading and conveying, coal bunkers, scales, feeders, pulverizers, stokers and ash handling equipment.	60,000
Power used by pulverizers, stokers and other coal and ash handling equipment	38,000
Fly ash and cinder disposal	20,000
Sluice water for ash system	5,000
Total direct savings	$208,000 per year
It may be necessary to install additional dust collecting facilities on each of Boilers "A" and "B" and "C" if we were to continue to burn coal. This total cost is roughly estimated to cost about $650,000. Potential operating savings by not having to install this equipment based on 5% maintenance and 5% depreciation is	65,000 per year

It should be noted that the above dust collecting facilities will not eliminate SO_2 problems in the flue gas and at

some time in the future, additional expenditures may be involved.

Additional intangible items resulting from all gas burning instead of coal are:

1. The coal track could be used for other process requirements such as hydrol or syrup systems.
2. Extended boiler life, less abrasion problems.
3. May be allowed extended periods between boiler inspections.
4. Reduction in mechanical stores items.

DFF:pld

G726

THOMPSON, HINE AND FLORY

NATIONAL CITY BANK BUILDING

CLEVELAND, OHIO 44114

DEFENDANT'S EXHIBIT 68

August 15, 1968

John T. Cusack, Esq.
Antitrust Division
Department of Justice
Room 2634
U. S. Court House
Chicago, Illinois 60604

Re: U. S. v. General Dynamics, et al.
Civil Action No. 67 C 1632 (N.D. Ill.)

Dear Mr. Cusack:

This has reference to your letter of August 7, 1968, in the captioned matter in which you asked confirmation of certain facts provided to you by Mr. Strausbaugh during your August 2 visit to Medusa's office.

Mr. Strausbaugh advises that there are four kilns at Dixon. Three of these kilns are 150 feet in length, are considered "short" kilns, and use coal having a maximum sulphur content of 1.2%.

The remaining kiln is 400 feet in length, is considered a "long" kiln, and uses coal having a maximum sulphur content of 3.2%.

I trust that the foregoing will clarify the matters about which you made inquiry in your August 7 letter.

Sincerely,

John F. McClatchey

JFMcClatchey/rg

cc: Mr. L. C. Strausbaugh

60-0-37-920

DEPARTMENT OF JUSTICE
AUG 1968
DIVISION OF RECORDS

Cusack

DEFENDANT'S EXHIBIT 69

GENERAL PORTLAND CEMENT COMPANY

4400 REPUBLIC NATIONAL BANK TOWER, P.O. BOX 324, DALLAS, TEXAS 75221
Area Code 214 742-1581

September 17, 1968

Department of Justice
Room 2634
United States Courthouse
Chicago, Illinois 60604

Attention: Mr. Ronald L. Futterman

Re: United States v. General Dynamics Corporation et al., Civil Action No. 67 C 1632 (N. D. Illinois)

Gentlemen:

The following information is submitted as requested by Mr. Futterman by phone. This is in lieu of questions submitted in a letter dated July 25, 1968 by Mr. John T. Cusak, Attorney, Midwest Office, Antitrust Division.

1. We do not purchase, nor have we purchased, any coal from mines located in the state of Illinois. This is true for two reasons. First, the freight from Illinois mines to our plants in Paulding, Ohio and Fredonia, Kansas makes the cost prohibitive; and secondly, the quality of the coal is poor since it does not come from deep mines. Mr. Futterman has asked about our policy relative to sulphur content and the methods for compensating for excessive sulphur. Sulphur is not a major factor in our purchases of coal because it combines with our product. Coal is purchased almost exclusively on BTU content and is purchased by the seam from which it is mined.

   Since mid-1963 all coal was purchased from North American Coal Corporation from their mine at Powhatan Point, Ohio. Purchases for the years in question were:

   1964 - 98,350.65 tons
   1965 - 99,228.80 tons
   1966 - 102,280.49 tons
   1967 - 90,760.30 tons

Cleared

60-0-37-0...

DEPARTMENT OF JUSTICE
SEP 23 1968
DIVISION OF RECORDS

3. Cement manufactured in our Paulding, Ohio plant is sold in Ohio, Indiana and Michigan. Our Fredonia, Kansas plant ships into the states of Kansas, Missouri, Arkansas and Oklahoma. Neither plant ships into the state of Illinois. Freight rates are such that we would not be competitive in this market.

Our Fredonia, Kansas plant is located in what is well known as the gas-belt, its primary fuel being gas. It does, however, on occasion, use coal during cold weather when the gas supply is curtailed for home consumer use. Our gas supply was last curtailed in February, 1963 during which period we used 171 tons of coal from inventory. Our last purchase of coal for kiln fuel at this plant was December, 1960 and the coal at that time was purchased from Pittsburgh Midway Coal Company from their mine in West Mineral, Kansas.

Yours truly,

R. M. Schafer
Treasurer

DEFENDANT'S EXHIBIT 70

MISSISSIPPI RIVER CORPORATION

9900 CLAYTON ROAD
ST. LOUIS, MISSOURI 63124

CLEON L. BURT
VICE PRESIDENT-LAW

PHONE
991-9900

September 29, 1969

Mr. Hugo Sims
Department of Justice
Room 2634 United States Courthouse
Chicago, Illinois 60604

Re: United States v. General Dynamics Corporation, et al., Civil Action No. 67 C 1632 (N.D. Ill.)

Dear Mr. Sims:

In our conversation of several days ago, you asked me certain questions about the burning of coal in our cement plant at Selma, Missouri. The questions, as I understood them, and the answers thereto are as follows:

1. Is it intended that our No. 2 Kiln, which is equipped to burn coal as an alternate fuel, will be switched to coal at times in the future as and when the gas supply is interrupted?

   - The answer to this question is that we do intend and expect to switch the No. 2 Kiln to the burning of coal when the gas supply is interrupted.

2. You inquired as to the usual period of time during which the natural gas supply to our plant is interrupted or curtailed.

   As to this, I cannot give you any better answer than I did verbally. As you know, the amount of interruption depends on numerous factors, the principal among which are the physical deliverability conditions of the pipeline supplier and the demands of domestic and commercial users. During the 1968-69 heating season, I am informed that gas was curtailed at the plant for between three and four months; whereas in the preceding year, the curtailment was much less severe. Accordingly, the curtailment can vary from almost nothing to three or four months. As a very rough approximation, I would say that 90 days out of the year might be a reasonable period on the average for cement plant gas curtailment.

Very truly yours,

Cleon L Burt

Cleon L. Burt

CLB:bjs

SUBJECT TO PROTECTIVE ORDER

CABLE ADDRESS "LANDWATER"
TEL. MU 2-3080

DEFENDANT'S EXHIBIT 71

HALL, PATTERSON, TAYLOR, MCNICOL & MARETT
(HALL, CUNNINGHAM & HAYWOOD)
41 EAST 42ND STREET
NEW YORK, N.Y. 10017

C. HAROLD TAYLOR
DONALD E. MCNICOL
JAMES J. MARETT
WILMOT B. MITCHELL
CHARLES J. EGAN, JR.

HAIG H. DAVIDIAN
PETER SIVIGLIA

CHESTER H. PATTERSON

ALFRED H. HAYWOOD
COUNSEL

May 27, 1968

Air Mail

John T. Cusack, Esq.
Department of Justice
Room 2634 United States Courthouse
Chicago, Illinois 60604

Dear Mr. Cusack:

In response to your letter to American Maize-Products Company dated April 15, 1968, the following information was gathered by American Maize-Products Company in response to your inquiries:

Under paragraph 1, total tons or dollar value of annual coal purchases for the years 1964 through 1967:

Year	Quantity Tons	Value
1964	117,365	$ 731,601
1965	112,639	697,196
1966	117,449	743,945
1967	106,483	693,437

The tonnage by mine for the years 1964 through 1967:

Year	Orient #3	Orient #4	Orient #5	Total
1964	111,858	5,784	---	117,642
1965	40,923	4,210	70,241	115,374
1966	6,418	368	108,486	115,272
1967	6,187	---	101,310	107,497

There is as you will notice, a difference between the figures showing tonnage by mine as opposed to Maize's coal purchases. The tonnage by mine figures are loaded weights at the mine. The annual coal purchases are the unloaded weights and the difference is lost in shipping.

60-0-37-925

DEPARTMENT OF JUSTICE
MAY 29 1968

The coal is used in coal burning boilers for the generation of steam. The steam in turn is used primarily in Maize's production department for evaporation and drying of Maize's products and for space heating.

As a secondary use the steam passes through turbines for the generation of electricity. The coal is burned in pulverized coal burning, high pressure boilers, which are also equipped to burn oil and gas as secondary fuels. The coal burning boilers are also equipped with continuous pilots, fueled by either gas or oil. Oil is burned in these boilers only when the coal supply is interrupted and gas is not available. Gas is the preferred secondary fuel. When interruptible gas is available, it is used in preference to all other fuels.

Annual purchases of fuel oil and gas are listed below:

Year	Quantity-Barrels	As Tons Of Coal	Value
1964	12,273	3,515	$ 38,968
1965	10,757	3,080	33,161
1966	11,569	3,313	34,417
1967	28,695	8,217	82,508

Year	Quantity-Cubic Feed	As Tons Of Coal	Value
1964	1,683,575,500	76,526	$ 631,749
1965	1,714,460,000	77,930	656,467
1966	1,879,110,000	85,414	771,827
1967	1,897,243,300	82,148	767,889

In addition to the coal burning equipment Maize does have package boilers which are equipped to burn oil or gas. Oil is the primary fuel of these boilers except when Interruptible gas is available. The package boilers are preferred over coal burning boilers because of the lower initial capital investment and the reduced time between ordering and start-up. They are also preferred because of the rising hue and cry to air pollution.

The gas as shown for the four years was not all consumed in the boilers. Maize does have gas fired feed dryers, gas fired starch dryers, and gas fired oil heating equipment for the production of dextrines. Gas is the only fuel which can be used in the drying and dextrinization processes.

The decision and reasons for burning a particular fuel is governed primarily by cost. The unit cost of Maize various fuels are as follows:

Coal	.02465	$/Therm
Oil	.04607	$/Therm
Gas (Firm)	.0483	$/Therm
Gas (Interr)	.0400	$/Therm

The plant can be equipped to convert from coal to gas or oil in the coal burning boilers with a few changes in piping and controls. This would probably require a capital investment of approximately $10,000. The removal, however, of the coal handling and burning equipment and the ash handling and disposing equipment would be much more expensive. No estimate is available on the cost of these removals.

There is no question that if Maize ever discontinued the burning of coal for any appreciable period, the possibility of ever returning to coal burning equipment would be very slim. It would not be practical to try to "moth-ball" the coal handling, milling and burning equipment.

If we can be of any further assistance, please do not hesitate to call on us.

Very truly yours,

Charles Egan

Charles J. Egan, Jr.

CJE,Jr./acg

HALL, PATTERSON, TAYLOR, McNICOL & MARETT

INLAND

INLAND STEEL COMPANY

DEFENDANT'S EXHIBIT 72

GEORGE A. RANNEY
VICE PRESIDENT AND GENERAL COUNSEL

May 20, 1968

ANSWERED BY LETTER DATED 5-22-68

Mr. John T. Cusack
Attorney, Midwest Office
Antitrust Division
Department of Justice
Room 2634, United States Courthouse
219 South Dearborn Street
Chicago, Illinois 60604

60-0-37-??? DEPARTMENT OF JUSTICE MAY 21 1968 DIVISION OF RECORDS Cusack

Re: United States v. General Dynamics Corporation et al., Civil Action No. 67 C 1632 (N.D. Ill.)

Dear Sir:

In response to your letter dated April 15, 1968, this will advise as follows:

1. Exhibit I attached hereto sets forth the net tons and dollar value delivered of metallurgical coal and steam coal purchased from firms supplying Inland Steel Company's East Chicago, Indiana, facility in each of the years 1964 through 1967. Mine source of coal where known is furnished.

Metallurgical coal is consumed in coke batteries for the production of coke for the blast furnaces. Steam coal is used to fire boilers for the production of steam.

2. Inland's East Chicago facility consumes certain other energy fuels for the purpose or purposes for which coal is consumed. In addition to steam coal, certain of the electric generating stations burn purchased petroleum coke, natural gas and fuel oil. Fuel oil is also consumed in the blast furnaces. Exhibit II attached hereto lists the quantities and

dollar value of the aforementioned petroleum coke, natural gas and fuel oil purchased in each of the years 1964 through 1967. The exhibit does not include blast furnace gas or coke oven gas consumed in certain of Inland's generating stations inasmuch as these are by-products produced within the plant and not purchased.

3. The following sets forth the reasons why Inland's East Chicago facility has not exclusively utilized one energy fuel in those instances where other energy fuels in addition to coal are consumed:

(a) In the blast furnaces, fuel oil is injected because (i) Inland's coke production is not sufficient to cover its total coke requirements and (ii) additional charging capacity is available in the skips for ore. For these purposes and in the quantities required fuel oil is cheaper, in general, than purchased coke.

(b) The use of different energy fuels in each of Inland's generating stations is dependent on the design characteristics of the station. In one generating station fuel oil is used to cover shortages in available powdered coal, the economics of fuel oil vs. powdered coal being approximately equal. A second generating station burns blast furnace gas, coke oven gas and fuel oil, the facility not being designed to consume coal. At a third generating station coal is the primary fuel, but petroleum coke and natural gas, when the latter is available, are burned as substitutes for coal for economic reasons.

Coal is not consumed in the open hearth furnaces, the basic oxygen furnaces or the reheating furnaces.

The information furnished on the enclosed exhibits has been prepared from a variety of internal sources. We cannot vouch for its accuracy in every respect. For example, with respect to steam coal purchases, we have been obliged in certain instances to estimate freight costs to arrive at delivered values.

We know of no documentation needed or helpful to substantiate or more fully explain the information herewith submitted.

I trust you will treat confidentially the information herewith voluntarily furnished to you.

Very truly yours,

George A. Ranney

George A. Ranney
Vice President and
General Counsel

GAR/jw
Enclosures

May 20, 1968

Exhibit I

INLAND STEEL COMPANY

METALLURGICAL COAL PURCHASES

Supplier	Mine	1964 Net Tons	1964 Delivered Value	1965 Net Tons	1965 Delivered Value	1966 Net Tons	1966 Delivered Value	1967 Net Tons	1967 Delivered Value
Inland Steel Co.*	Wheelwright, Ky.	1,549,704	$15,605,519	1,638,139	$16,446,916	135,653	$ 1,356,530		
Island Creek Coal Co.	Wheelwright, Ky.					1,569,262	15,849,546	1,676,894	$17,255,239
Island Creek Coal Co.	Bartley #6, W. Va.					108,567	1,155,153	100,638	1,105,005
Freeman Coal Mining Corp.	Orient #3, Ill.	307,474	2,410,596	330,095	2,558,236	401,217	3,125,480	386,267	3,009,020
Old Ben Coal Corp.	Old Ben #21, Ill.	73,745	555,300	38,637	291,709	58,357	434,176	250,310	1,937,399
Bishop Coal Co.	Bishop, W. Va.	1,701,208	18,645,240	1,655,609	18,128,919	1,514,434	16,704,207	1,563,145	17,538,487
Jewell Ridge Coal Corp.	Jewell Valley, Va.	234,191	2,494,134	229,715	2,492,408	169,088	1,868,422		
The Pittston Co.	Jewell Valley, Va.					169,088	1,868,422	123,206	1,452,599
Consolidation Coal Co.	Jenkinjones, W. Va.							55,766	639,078
		3,866,322	$39,710,789	3,892,195	$39,918,188	4,125,666	$42,361,936	4,156,226	$42,936,827

STEAM COAL PURCHASES

Supplier	1964 Net Tons	1964 Delivered Value	1965 Net Tons	1965 Delivered Value	1966 Net Tons	1966 Delivered Value	1967 Net Tons	1967 Delivered Value
Freeman Coal Mining Corp.	94,806	$ 627,595	6,404	$ 47,708	3,217	$ 24,128		
Sterling-Midland Coal Co.	42,400	308,213	19,932	144,766	2,049	15,366		
Bell & Zoller Coal Co.	43,077	263,684	12,427	87,051	5,660	42,217	18,878	$ 140,076
Royal Fuel Corp.	13,803	101,472	38,173	224,457	23,130	146,697	150,208	946,332
Republic Coal & Coke Co.	46,071	321,117	58,447	331,484	41,901	250,568	112,286	782,632
United Electric Coal Cos.	62,416	424,529			2,524	15,019		
West Kentucky Coal Co.	7,342	56,679						
Island Creek Coal Co.			5,210	37,879	1,035	7,161		
O'Keefe Bros. Coal Co.			69,825	420,346				
Southern Illinois Co-op Coal Sales Co.			227,032	1,210,080	294,876	1,724,412	27,095	176,118
	309,915	$ 2,103,289	437,450	$ 2,503,771	374,392	$ 2,225,568	308,467	$ 2,045,158

*, Coal supplied from Inland Steel Co., Wheelwright, Ky. Mine, valued at market.

May 20, 1968

Exhibit II

INLAND STEEL COMPANY

PURCHASES OF CERTAIN FUELS FOR PURPOSES STATED BELOW

Description	1964 Net Tons	1964 Delivered Value	1965 Net Tons	1965 Delivered Value	1966 Net Tons	1966 Delivered Value	1967 Net Tons	1967 Delivered Value
Petroleum Coke								
Power Stations	-	-	56, 118	$ 350, 739	128, 239	$ 788, 668	97, 126	$ 709, 022
	Gals.		Gals.		Gals.		Gals.	
Fuel Oil								
Power Stations	5, 306, 248	$ 384, 703	2, 188, 813	$ 169, 633	3, 463, 807	$ 251, 126	4, 149, 600	$ 300, 846
Blast Furnaces	-	-	-	-	4, 216, 469	305, 694	3, 390, 059	245, 779
	MCF		MCF		MCF		MCF	
Natural Gas								
Power Stations	5, 036, 993	$1, 820, 873	3, 583, 989	$1, 254, 396	5, 288, 242	$1, 903, 767	5, 560, 337	$1, 898, 299

DEFENDANT'S EXHIBIT 73

Vulcan Materials Company

MIDWEST DIVISION / 20 N. WACKER DRIVE • CHICAGO, ILLINOIS 60606 • TELEPHONE FR 2-8400

W. JOE SHAW
PRESIDENT

November 28, 1966

Mr. John Cusack, Attorney
U. S. Department of Justice
Anti-Trust Division
219 South Dearborn Street
Chicago 4, Illinois

Dear Mr. Cusack:

Following our recent telephone conversation, I talked to various persons in this office about the question that you raised as to whether or not the acquisition of United Electric Coal Company by General Dynamics would in any way affect our sources of coal.

I do not believe we have ever purchased coal from United Electric Coal Company, and I believe that you pointed out in our conversation that United Electric Coal Company supplied coal primarily to the utilities industry.

We have purchased coal from a number of companies in the Midwest, and we do not believe that the acquisition of United Electric Coal Company by General Dynamics would have any effect on our future purchases of coal.

I hope this answers your recent inquiry.

Yours very truly,

W. J. Shaw

W. J. Shaw

WJS:s

Answered

60-0-37
DEPARTMENT OF JUSTICE
NOV 29 1966
DIVISION OF RECORDS
Cusack

EXHIBIT 74

RIVER CEMENT COMPANY

1050. BRENTWOOD BLVD. • ST. LOUIS, MO. 63105 • PHONE: VOLUNTEER 3-5500

Direct Reply to:

9900 Clayton Road
St. Louis, Missouri 63124

September 11, 1968

Mr. Edwin M. Zimmerman
Assistant Attorney General
Department of Justice
Room 2634 United States Courthouse
Chicago, Illinois 60604

Re: United States v. General Dynamics Corporation, et al., Civil Action No. 67 C 1632 (N.D. Illinois)

Dear Mr. Zimmerman:

This is in response to your letter of August 5, 1968, requesting information of our company in connection with the above case.

The questions and answers are as follows:

1.A. Total tons and dollar value of annual coal purchases from all firms supplying your Festus, Missouri plant in each of the years 1964 through 1967.

No coal was purchased for our Festus (Selma) Missouri plant during the years 1964 through 1967.

B. Please state the purpose for which coal is required and generally describe the equipment in which coal is consumed.

Coal is not required in the operation of the plant. Kiln No. 1 of the plant, presently in operation, is not equipped to burn coal. Kiln No. 2, which is under construction, will be equipped to burn coal when necessary or desirable. If and when coal is consumed, it would be consumed for firing a rotary clinker producing kiln (Kiln No. 2) in the production of portland cement, said kiln to be 17-1/2' x 16' x 560' in size.

60-0-37-[illegible]

DEPARTMENT OF JUSTICE
SEP 13 1968
DIVISION OF RECORDS

2.A. Please state whether your Festus, Missouri plant consumes any other energy fuel for the purpose for which coal is required.

See answer to question 1.B. Both natural gas and No. 6 oil are used at the plant for firing Kiln No. 1. Kiln No. 2 will use natural gas and coal.

B. If so, state for each such fuel the annual dollar and quantity (barrels of oil, cubic feet of gas, etc.) or equivalent coal ton purchases for the years 1964 through 1967.

	No. 6 Fuel Oil		Natural Gas	
	Gallons	$	MCF	$
1964	-0-	-0-	-0-	-0-
1965	2,711,125	191,942	1,392,786	375,634
1966	303,776	21,524	2,773,905	748,351
1967	1,267,863	132,650	2,773,124	780,439

C. Also, please generally describe the equipment in which each fuel is consumed.

Kiln No. 1, being a rotary kiln 17-1/2' x 16' x 560' in size.

3.A. If consumption of other energy fuels is in addition to coal consumption, please state the reason(s) why the plant involved does not exclusively utilize one energy fuel.

Consumption of other energy fuels is not <u>in addition</u> to coal consumption since there has been <u>no coal</u> consumption to date. However, the plant is equipped to utilize more than one fuel to assure continuous operation of the plant, in case one or more of the possible fuels is not available or becomes non-competitive in cost.

Mr. Edwin M. Zimmerman
Department of Justice
Chicago, Illinois

Page 3
September 11, 1968

B. If consumption of other energy fuels substitutes for consumption of coal, please indicate the criteria used to determine when it is appropriate to switch from one energy fuel to another.

Other energy fuels will not be substituted for coal; on the contrary, coal may be substituted for other fuels on Kiln No. 2. Cost and availability would be the primary criteria for determining when it is appropriate to switch from one energy fuel to another. However, various other factors would no doubt be involved which cannot be determined in advance. Such factors might include cleanliness, fuel handling problems, etc.

4. Please furnish to us copies of any charts, memoranda, surveys or other documents which would substantiate or more fully explain the information requested above or which bear on the advantages, disadvantages, or uniqueness of any of the energy fuel sources. Please include any studies or estimates as to the feasibility of immediately converting from coal to any other energy fuel source.

None available.

5.A. Please state whether or not a ceiling is placed on the sulfur content or the coal purchased, and if so, state the maximum tolerable sulfur content and the present sulfur content of coal consumed.

Should coal be purchased in the future, we anticipate that we would specify a maximum tolerable sulfur content of about 3.5% on a dry basis.

B. Also state whether or not these tolerances may be adjusted to compensate for low-sulfur or high-sulfur raw materials used in the manufacture of cement.

Not presently determinable.

Very truly yours,

RIVER CEMENT COMPANY

Cleon L. Burt

Cleon L. Burt
General Attorney

CLB:bjs

DEFENDANT'S EXHIBIT 75

MISSOURI PORTLAND CEMENT COMPANY

7751 CARONDELET AVENUE
ST. LOUIS, MISSOURI 63105

WILLIAM J. BRANMAN, JR.
VICE PRESIDENT, SECRETARY

January 24, 1969

Mr. John T. Cusack
Attorney, Midwest Office
Antitrust Division
Department of Justice
Room 2634 United States Courthouse
Chicago, Illinois 60604

Re: United States v. General Dynamics Corporation et al., Civil Action No. 67 C 1632 (N.D. Ill.)

In reply to your letter of January 22 regarding the above matter, I shall further clarify my letter of January 20 regarding gas purchases at the St. Louis and Joppa plants.

Gas consumed at these plants in the years indicated was primarily used in conjunction with coal for technical reasons. In general, the rates for this gas would be considered firm rather than interruptible. I am not familiar with the exact meaning of the term "seasonal" in your letter. With respect to the St. Louis plant, it would be significant to know that gas is now used as the predominant fuel as it is now less expensive than coal at this point.

Very truly yours,

W J Branman Jr

WJB:aa

DEPARTMENT OF JUSTICE
JAN 27 1969

DEFENDANT'S EXHIBIT 76

1/3/67

LAW OFFICES

NORMAN, ENGELHARDT, ZIMMERMAN, FRANKE & LAURITZEN

60 WEST WASHINGTON STREET

CHICAGO 60602

TELEPHONE 236-0602

HAROLD W. NORMAN
WILLIAM R. ENGELHARDT
AUSTIN W. ZIMMERMAN
ALLYN J. FRANKE
CHRISTIAN M. LAURITZEN II
GEORGE H. REDDING, JR.
RALPH MILLER
DONALD S. PETERSEN
JOHN C. WOULFE
WILLIAM K. BLANCHARD
ELLIOTT COHEN
WILLIAM P. O'KEEFE, JR.
ROGER R. FROSS

CABLE-ESRON CHICAGO
FOR LONG DISTANCE
DIAL 312-236-0602

December 23, 1966

Mr. Bertram M. Long
Assistant Chief, Midwest Office
Antitrust Division
United States Department of Justice
Room 2634 United States Courthouse
Chicago, Illinois 60604

Dear Mr. Long:

In accordance with our telephone conversation, attached is a compilation showing the amount of coal in dollars and in tons purchased by Marquette Cement Manufacturing Company during the years 1964 and 1965 for its cement plants at DesMoines, Iowa; Cape Girardeau, Missouri and Oglesby, Illinois.

Due to the location of United Electric Coal Company and its ability to furnish coal on barges, Marquette, since at least 1938, has obtained its coal for the Oglesby plant under long-term contracts negotiated with United Electric Coal Company.

Similarly, because of its location, United Electric Coal Company has not been able and has not endeavored to supply coal to the Cape Girardeau or Des Moines plants.

In view of the factual circumstances, Marquette cannot see that there would be any effect upon it if the United Electric Coal Company is eliminated as an independent supplier of coal.

I am informed that Marquette has not had any arrangements or understandings with General Dynamics Corporation or any subsidiary thereof to purchase coal from General Dynamics Corporation or any subsidiary thereof on condition or

DEPARTMENT OF JUSTICE
DEC 27 1966
DIVISION OF RECORDS
Mr. Cusack

ORMAN, ENGELHARDT, ZIMMERMAN, FRANKE & URITZEN

Mr. Bertram M. Long -2- December 23, 1966

consideration that General Dynamics or any subsidiary thereof purchase cement from Marquette.

I trust the foregoing gives you the information you desire.

Very truly yours,

William R. Engelhardt

WRE:ddb
Enc.

COAL PURCHASES - 1964 and 1965

PLANT	1964 Tons	1964 Dollar Value	1965 Tons	1965 Dollar Value
Des Moines Supplier				
Beard Coal Company	846.80	3,133.19	1,152.20	4,263.00
Consumers Consolidated Co.	696.40	2,541.89	-	-
Freeman Coal Company	16,354.00	64,761.84	29,355.76	117,423.04
University Avenue Coal Co.	8,044.30	29,255.00	1,253.25	4,586.89
Old Ben Coal Company	-	-	2,540.65	10,162.60
Peabody Coal Company	-	-	6,312.75	28,634.76
Cape Girardeau Supplier				
Freeman Coal Company	150,379.45	618.664.22	167,624.75	707,309.59
Republic Coal Company	45,035,10	154,159.19	25,960.90	86,940.73
Oglesby Supplier				
United Electric Coal Company	300,324.45	1,225,984.47	278,496.25	1,173,193.30

DEFENDANT'S EXHIBIT 77

Central Illinois Light Company

GENERAL OFFICES PEORIA, ILL. 61602

October 21, 1966

Mr. Bertram M. Long
Assistant Chief, Midwest Office
Antitrust Division
United States Department of Justice
Room 2634, United States Courthouse
Chicago, Illinois 60604

Dear Mr. Long:

Referring to your letter of October 14, 1966 addressed to Mr. Herbert A. Blair of our Company, File No. 60-0-37, we are enclosing a list of suppliers of coal for the years 1964 and 1965, the quantity each of these suppliers furnished, and the payments made to each supplier.

No coal received by the Central Illinois Light Company in the years 1964 and 1965 was mined outside of the State of Illinois.

United Electric Coal Company and Freeman Coal Mining Corporation have both bid on supplying coal to our Company; however, we have not considered these two firms to be competitors inasmuch as Freeman supplied our Springfield Station and United Electric supplied our Peoria plants.

To answer question No. 5,

> "What effect, if any, may there be on your firm and on other public utilities if The United Electric Coal Companies is eliminated as an independent supplier of coal "

would be highly speculative in connection with the effect on other public utilities; however, we feel the elimination of United Electric Coal Company, as an independent supplier, would have little or no effect upon the Central Illinois Light Company inasmuch as we have a long term contract which runs to a period when, in our opinion, the reserves in the mine that now supplies us, will be exhausted.

60-0-37
DEPARTMENT OF JUSTICE
OCT 24 1966
DIVISION OF RECORDS

Very truly yours,

Q. W. Wellington
Senior Vice President, Operations

QWW:afb
cc: Herbert A. Blair

DEFENDANT'S EXHIBIT 78

MISSOURI PORTLAND CEMENT COMPANY

7751 CARONDELET AVENUE

ST. LOUIS, MISSOURI 63105

WILLIAM J. BRAMMAN, JR.
VICE PRESIDENT, SECRETARY

September 22, 1969

Mr. Hugo S. Sims, III
Attorney, Midwest Office
Antitrust Division
Department of Justice
Room 2634 United States Courthouse
Chicago, Illinois 60604

Re: United States vs. General Dynamics Corporation, et al

Dear Mr. Sims:

In response to your recent telephone inquiry regarding the above matter, I will attempt to clarify the basis for useage of coal and gas at our three midwestern cement manufacturing plants. This data will supplement that previously requested and supplied in my letters of January 20, January 24, May 2, and May 21, 1969.

Kansas City Plant. Gas has been used for all purposes beginning sometime in 1964 to date. The rate is considered to be interruptible but the supply is sufficient to serve us without interruption throughout our entire production year. Production is normally discontinued for a couple of winter months for economic reasons. Gas is used because it is cheaper than coal.

St. Louis Plant. Over the years, coal and gas have been alternated as fuels for kiln operations depending upon the price of each fuel. The gas used for the years 1964 through 1967, as reported in my letter of January 20, 1969, was for heating purposes only. This gas was purchased on a non-interruptible basis. Coal was used exclusively for kiln operations because at that time it was more economical under a long-term contract. For more than a year, however, we have reverted to alternating coal and gas as fuels as gas prices have become more competitive. For the twelve months ended August 31, 1969, coal consumption amounted to $449,371 for 72,646 tons and gas consumption amounted to $554,828 for 2,173,972 MCF. This gas was supplied on an interruptible basis at a lower cost than coal. Coal was utilized only during the cold weather months when the supply of gas became uncertain.

60-0-37-[illegible]
DEPARTMENT OF JUSTICE
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RECORDS

Dusacek

Mr. Hugo S. Sims, III
Page 2
September 22, 1969

Joppa Plant. To date, coal has been the cheapest fuel available at this plant since its completion in 1963. For this reason it has been used exclusively for kiln operations. Gas could and would be utilized for this purpose if it should become cheaper than coal. The gas that has been used at this plant has been for other purposes, such as heating and drying, for which it is preferable for technological reasons. This gas is supplied on a non-interruptible basis.

In summary, kiln operations at our three plants presently utilize three different types of fuel supply -- coal at Joppa, gas at Kansas City and a combination of coal and gas at St. Louis. At two of these locations, St. Louis and Kansas City, the fuels utilized have changed in the past five years due to changes in the competitive prices of coal and gas. Cost is the determining factor.

Very truly yours,

WJB:bmt

United States of America

DEFENDANT'S EXHIBIT 80

Federal Trade Commission

Joseph W. Shea, Secretary of the Federal Trade Commission, and official custodian of its records, do hereby certify that attached is a full, true, and complete copy of:

Respondent Exhibit No. 184 A-F received in evidence in Federal Trade Commission Docket 8765, in the matter of Kennecott Copper Corporation.

IN WITNESS WHEREOF, I have hereunto subscribed my name and caused the seal of the Federal Trade Commission to be affixed this 16th day of July, A.D. 1969, at Washington, D.C.

Joseph W. Shea

Joseph W. Shea,
Secretary.

F.T.C. [illegible]

SELECTED INFORMATION REQUESTED IN SUBPOENA DUCES TECUM ISSUED BY FEDERAL TRADE COMMISSION UNDER DATE OF DECEMBER 31, 1968 ON BEHALF OF KENNECOTT COPPER CORPORATION

* * * * *

MARCH 6, 1969

FEDERAL TRADE COMMISSION
Docket No. 8765 RESPONDENT Exhibit No. 1842
In the Matter of: Kennecott Copper
Date 5/14/69 Witness Reporter P.F

PRICE WATERHOUSE & CO.

PRICE WATERHOUSE & CO.

60 BROAD STREET
NEW YORK 10004

March 6, 1969

The Honorable Donald R. Moore
Hearing Examiner
Federal Trade Commission
1101 Pennsylvania Avenue
Washington, D. C.

FEDERAL TRADE COMMISSION
Docket No. 7765 ... Exhibit No. 124B

Dear Mr. Moore:

KENNECOTT COPPER CORPORATION

In accordance with provisions of Part B of Attachment A to subpoena duces tecum issued by the Federal Trade Commission under date of December 31, 1968 on behalf of Kennecott Copper Corporation, we have prepared and submit for your information the exhibits listed below:

Exhibit I - Companies which responded to subpoena duces tecum
II - Selected information requested in subpoena duces tecum

We have prepared Exhibit II from data furnished to us by the participating companies listed in Exhibit I. Our work was limited to receiving and compiling the data into composite form, hence we did not compare the individual company data submitted to us with the records of such companies and no audit procedures were carried out by us. Accordingly, while we are satisfied that the data have been properly summarized, we can assume no responsibility for the underlying amounts and figures.

Every possible precaution has been taken to prevent the direct or inferential identification of the data of a particular company in the composite amounts and figures.

* * * * *

Should you have any questions about our procedures in compiling the data, please let us know.

Yours very truly,

Price Waterhouse & Co.

COMPANIES WHICH RESPONDED TO SUBPOENA DUCES TECUM ISSUED BY FEDERAL TRADE COMMISSION UNDER DATE OF DECEMBER 31, 1968 ON BEHALF OF KENNECOTT COPPER CORPORATION

FEDERAL TRADE COMMISSION
Docket No. 7765 RESPONDENTS Exhibit No. 1246

American Oil Company

Atlantic Richfield Company

Cities Service Company

Continental Oil Company

Getty Oil Company

Gulf Oil Corporation

Humble Oil & Refining Company

Mobil Oil Corporation

Phillips Petroleum Company

Shell Oil Company

Sinclair Oil Corporation

Standard Oil Company of California

Sun Oil Company

Texaco, Inc.

Union Oil Company of California

EXHIBIT II

SELECTED INFORMATION REQUESTED IN SUBPOENA DUCES TECUM ISSUED BY FEDERAL TRADE COMMISSION UNDER DATE OF DECEMBER 31, 1968 ON BEHALF OF KENNECOTT COPPER CORPORATION

(Unaudited)

1. Of the fifteen companies (listed in Exhibit I) served with subpoena duces tecum, the five companies shown below reported holding recoverable coal reserves in 1967:

Atlantic Richfield Company
Continental Oil Company
Gulf Oil Corporation
Humble Oil & Refining Company
Sinclair Oil Corporation

2. The above five companies reported holdings of recoverable coal reserves and acres of coal lands as follows:

(a) Total recoverable coal reserves of 7.8 million tons* in 1960 and 10,188.7 million tons in 1967.

(b) Total acres of coal lands of 4,524 acres in 1960 and 2,491,079 acres in 1967.

(c) Total recoverable coal reserves in 1960 and 1967, respectively, of:

(i) Zero million tons and zero million tons in Arizona.
(ii) Zero million tons and 234.0 million tons in Colorado.
(iii) Zero million tons and zero million tons in Idaho.
(iv) Zero million tons and 106.0 million tons in Montana.
(v) Zero million tons and zero million tons in Nevada.
(vi) Zero million tons and 222.0 million tons in New Mexico.
(vii) Zero million tons and 296.5 million tons in Utah.
(viii) Zero million tons and 1,276.0 million tons in Wyoming.
(ix) Zero million tons and 2,537.2 million tons in states west of the Mississippi River.

*Throughout tons refers to short tons.

FEDERAL TRADE COMMISSION

...tal acres of coal lands in 1960 and 1967, respectively, of:

(i) Zero acres and zero acres in Arizona.
(ii) Zero acres and 41,400 acres in Colorado.
(iii) Zero acres and zero acres in Idaho.
(iv) Zero acres and 7,900 acres in Montana.
(v) Zero acres and zero acres in Nevada.
(vi) Zero acres and 46,614 acres in New Mexico.
(vii) Zero acres and 73,064 acres in Utah.
(viii) Zero acres and 367,000 acres in Wyoming.
(ix) Zero acres and 635,782 acres in states west of the Mississippi River.

3. The five companies (listed in Item 1) holding recoverable coal reserves in the United States in 1967 are grouped as follows:

(a) One company reported total recoverable coal reserves of over 5,000 million tons.
(b) Two companies reported total recoverable coal reserves each of 1,000 million to 2,750 million tons.
(c) Two companies reported total recoverable coal reserves each of under 1,000 million tons.

4. The five companies (listed in Item 1) first acquired recoverable coal reserves or coal lands as follows:

(a) One company in 1955
(b) One company in 1962
(c) One company in 1963
(d) One company in 1965
(e) One company in 1966

5. Of the five companies (listed in Item 1), none reported holding recoverable coal reserves in Utah in 1960. Two of the five companies reported holding such reserves in 1967.

6. Of the five companies (listed in Item 1), none reported holding recoverable coal reserves in Arizona, Colorado, Idaho, Montana, Nevada, New Mexico and Wyoming in 1960. Four of the five companies reported holding, in aggregate, such reserves in Colorado, Montana, New Mexico and Wyoming in 1967; no coal reserves were reported by such companies for Arizona, Idaho and Nevada in 1967.

7. Of the five companies (listed in Item 1), none reported holding recoverable coal reserves in states west of the Mississippi River in 1960. Four of the five companies reported holding such reserves in 1967

. Of the fifteen companies (listed in Exhibit I), eleven reported expenditures for research, study, or development in the conversion of coal to synthetic fuels, with the following breakdown by years:

(a) Three companies in 1963
(b) Four companies in 1964
(c) Five companies in 1965
(d) Seven companies in 1966
(e) Seven companies in 1967
(f) Four companies in period 1963-1967*

*Four companies reported estimated aggregate expenditures of $291,300 for the period 1963-1967. No specific breakdown was furnished for the individual years in that period.

9. The eleven companies referred to in Item 8 reported expenditures of $14,138,748 for research, study, or development in the conversion of coal to synthetic fuels during the years 1963-1967, both inclusive, of which $6,508,473 was reported as company funds and $7,630,275 as grants from others.

FEDERAL TRADE COMMISSION
Docket No. 7?6 C respondents Exhibit No. 174-e

DX 81 Standard Oil Company (New Jersey)

1968 Annual Report

* * *

March 5, 19[illegible]

We are pleased to report that earnings of Standard Oil Company (New Jersey) in 1968 increased $122 million to a record $1,277 million, or $5.94 per share, up 10.8 per cent over the comparable earnings of $5.36 per share in 1967. Accounting changes, which are described in the notes to the accompanying financial statements, had the effect of reducing the earnings figures for both years.

Dividend payments to shareholders were increased for the eighth year in a row—from $3.45 per share in 1967 to $3.65 in 1968. This was the 86th consecutive year of dividend distributions.

Total revenue rose to $15,873 million, an increase of 7.7 per cent over 1967.

Production of crude oil and natural gas liquids reached a new high rate of 5,225,000 barrels a day, up 8.2 per cent over 1967, with marked increases in production in the United States, Venezuela, and Libya. Improved manufacturing facilities in all areas and expanded capacity in Europe made possible record refinery crude oil runs of 4,621,000 barrels a day. Worldwide sales of petroleum products increased 5.0 per cent to 4,881,000 barrels a day.

The production and sale of natural gas is making an increasingly significant contribution to Jersey's total revenue. In 1968 sales of natural gas increased sharply to 5,296 million cubic feet a day. Sales in the large U.S. market accounted for 80.8 per cent of the total. However, fast-growing sales in Europe more than doubled those of 1967. Jersey's 30 per cent interest in production from the Groningen field in the Netherlands, for sale in that country and for export, is expected to double again by 1970. Initial deliveries of natural gas from the fields in the North Sea, imminent shipment of liquefied natural gas from Libya to Spain and Italy, and the beginning of gas deliveries from our joint venture in Australia also attest to the growing importance of gas to the company's future results.

Jersey's performance in 1968 is attributable in large measure to the results of an aggressive investment program. Capital expenditures made in recent years have provided the capacity for significant increases in operating volumes. Con-

tinued efforts toward cost reduction and efficiency also have contributed to improved profitability. Jersey's return on average shareholders' equity increased to 13.3 per cent last year, up from 12.6 per cent the year before and the highest in more than a decade. Further improvement is expected in 1969.

In 1968 company investments in new property, plant, and equipment amounted to $1,944 million. Slightly more than half of the 1968 investments were in the United States. A further $195 million was spent and charged to income in 1968 as part of the company's worldwide exploration program which is designed to support the objectives of increasing reserves and of diversifying the company's sources of crude oil and natural gas.

Affiliates are finding and taking advantage of major opportunities for increasing earnings in the future. In addition to the growth of natural gas sales, the investment programs associated with crude oil production from the Alaskan Arctic and offshore southeastern Australia are of particular importance. The grand scale of these exciting opportunities requires a continued high level of capital expenditures—a level which the company's strong financial position makes possible to maintain.

The demand for energy throughout the world continues to increase steadily. Improvements in the standard of living in industrialized nations and greater realization of aspirations among developing countries ensure dynamic growth in the demand for energy.

In the United States, total energy requirements are estimated to increase at an average of 4 per cent a year, which means in ten years they will be almost half again as large as they are today. The demand for oil and gas, which supply three-fourths of these requirements, is anticipated to grow proportionately. Energy consumption is increasing even faster elsewhere in the free world, and oil and natural gas are expected to supply nearly all the near-term growth in these energy requirements.

Jersey affiliates will maintain their traditional leading position as suppliers of petroleum products to free world countries. Their demonstrated success in meeting the needs of growing markets in the continents of the globe promises to continue the company's growth and profit improvement in 1969 and the years ahead. Our confidence in the future is strengthened by the enthusiastic commitment of the thousands of company employees around the world. We appreciate their loyal efforts as well as the continued support of our shareholders.

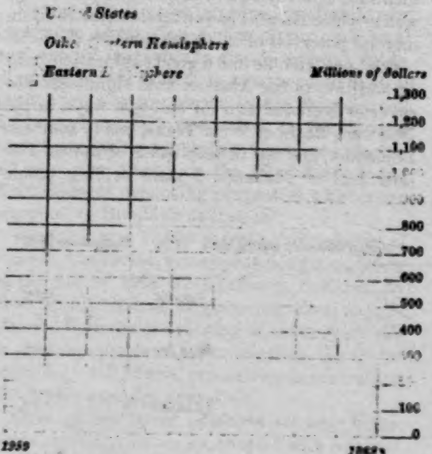
FOR THE BOARD OF DIRECTORS

M. L. HAIDER, *Chairman* J. K. JAMIESON, *President*

(1967 restated, see page 23)

Total revenue, *millions of dollars*	$15,[illegible]73	$14,7[illegible]*
Net income, *millions of dollars*	$ 1,277	$ 1,155*
Cash dividends paid, *millions of dollars*	$ 725	$ 743
Shareholders' equity, *millions of dollars*	$ 9,856	$ 9,375
Net income *per share*	$ 5.94	$ 5.36*
Cash dividends *per share*	$ 3.65	$ 3.45
Shareholders' equity *per share*	$ 45.23	$ 43.57
Net income to average shareholders' equity, *per cent*	13.3	12.6*
Net income to total revenue, *per cent*	8.0	7.8*

**Excludes estimated recoveries of $49 million or $0.18 a share on claims for World War II losses.*



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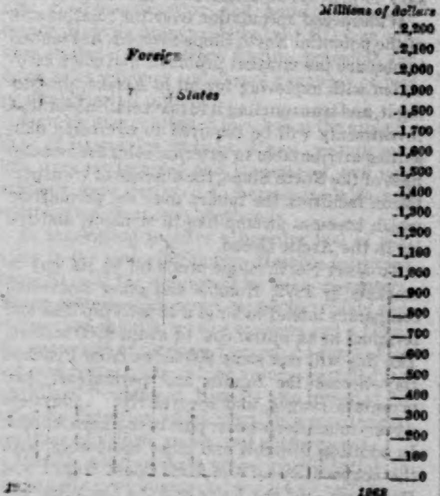


Capit ditures

United States The vigorous growth of the United States economy accelerated the demand for energy during 1968. Humble Oil & Refining Company continued to contribute significantly to Jersey's results and to be a leader in the domestic petroleum industry.

The year's highlight was the discovery of oil and gas on the North Slope of Alaska by a joint venture composed of Humble and Atlantic Richfield Company. One successful well was drilled at Prudhoe Bay and another at Sag River, seven miles away. In this North Slope area, Humble has a 50 per cent interest in approximately 800,000 acres. Evaluation drilling and seismic work are continuing. The discovery appears to be very significant, but further drilling is necessary to provide an estimate of the reserves.

Widespread speculation over the relative size of the potential North Slope reserves has tended to obscure the unusual problems and costs associated with exploring for oil in Alaska, producing it, and transporting it to markets. Substantial investments will be required to overcome difficulties attributable to extreme cold, the remoteness of the North Slope, the absence of transportation facilities, the tundra over the permafrost which becomes swamp-like in summer, and the ice in the Arctic Ocean.

To start North Slope crude oil on its way to markets by 1972, Humble and other interested companies intend to build a 48-inch pipeline and terminal at an initial cost of about $900 million. The line will run some 800 miles from Prudhoe Bay—across the tundra and permafrost, two mountain ranges, and several river valleys—to a year-round deep-water port in southern Alaska. In addition, Humble and other companies, with the cooperation of the U.S. Coast Guard and Department of the Navy and the Canadian Department of Transport, plan to test the feasibility and economics of carrying oil through the Arctic Ocean, between Canada's Arctic islands, and into the North Atlantic. This icy route, known as the Northwest Passage, will be tested later in 1969 by a chartered tanker which will have an exceptionally strong hull, an icebreaker bow, and special equipment to protect propeller and rudder.

Humble and other companies invested substantial sums in 1968 to acquire leases from the federal government off the coasts of California and Texas. Offshore California, in the Santa Barbara Channel, three discovery wells have been announced, in one of which Humble has an interest. Humble also had encouraging results at other locations nearby. Further work will be required to define the magnitude of reserves. Offshore Texas, in the Gulf of Mexico, exploration results so far have been disappointing. Some indications of oil and gas were encountered at one well in which Humble has an interest, but the commercial potential of this area remains doubtful.

Onshore Humble had a good exploration year. In addition to the Alaskan find, significant discoveries included two oil and gas wells in the Delaware Basin of West Texas, one in southern Louisiana, and one in deep sands of the old Pollard field of Alabama. Future drilling should

United States operating data	1968	Change from 1967
	948,000	*7.0%*
	943,000	*3.4%*
	1,518,000	*2.2%*
	4,280	*13.8%*

Production of crude oil and natural gas liquids, *barrels a day*		4,892,000	4,458,000	
	Other crude oil offtake under special arrangements	333,000	372,000	
	Total	5,225,000	4,830,000	8.2%
Refinery runs, *barrels a day*		4,621,000	4,437,000	4.1%
Petroleum product sales, *barrels a day*		4,881,000	4,647,000	5.0%
Natural gas sales, *million cubic feet a day*		5,295	4,419	19.8%
Chemical revenues, *millions of dollars*		933	815	14.4%
	Affiliate owned	6,082,000	5,415,000	
Tankers, *deadweight tons capacity*	*Period chartered*	7,788,000	7,384,000	
	Total	13,870,000	12,799,000	8.4%
Pipelines, *barrels a day throughput*		6,509,000	5,990,000	8.7%

provide sufficient information for substantial reserve additions from these discoveries during the next few years.

During 1968 Humble improved profitability by increasing production and applying additional cost control measures in its oil and gas fields. A computerized system to measure and control production was introduced in the Friendswood field near Houston to test techniques for automation of producing properties. Continued emphasis also was placed on the identification and disposition of producing properties which were marginal to Humble's operations.

Humble's new 72,000-barrel-a-day refinery at Benicia, California, was approaching completion at the end of 1968. This refinery, designed by Esso Research and Engineering Company, is planned for intensive refining of heavy crude oils to give high yields of motor gasoline. Computer technology will be used extensively in controlling this highly complex operation.

Sales of petroleum products set new highs. New operating efficiencies, coupled with relatively firm prices for these greater volumes, helped to offset rising costs for goods and services.

Taking advantage of opportunities offered by new road construction and housing developments, Humble inaugurated about 500 new service stations in locations having potential for large sales volumes and closed a number of less profitable retail outlets.

Humble also continued to enhance the appearance of its service stations. Many existing outlets were modernized and landscaped, and new stations were designed to harmonize with and complement their neighborhoods.

In innovating to offer a broader line of services to the motoring public, Humble increased from 30 to 47 the number of its car care centers. These centers offer more complete vehicle servicing than regular service stations and a Humble guarantee of work performed. At some of its car care centers, where high volume justified the additional investment, Humble also installed diagnostic facilities which provide computerized analyses of vehicle safety and performance.

Humble continued its active participation in the rapidly growing market for jet aircraft fuel, deriving about 10 per cent of its 1968 market sales volume from this product. Humble and

other affiliates combined increased by about 16 per cent their 1968 worldwide commercial jet fuel sales. Investments were made in refining, transportation, and storage facilities in the United States and abroad to enable affiliates to keep pace with the growth of the airlines' passenger and cargo fleets. The first of the new jumbo jet aircraft will use Esso fuels in New York and key European cities late this year.

Humble revenues benefited from significant growth in sales of both natural gas and liquefied petroleum gas. Sales of natural gas, already at high levels, grew by 14 per cent, owing primarily to deliveries under long-term contracts made in previous years. Sales of natural gas plant liquids were up 18 per cent, mostly as a result of increased petrochemical feedstock sales. Over a three-year period and at a cost of $80 million, Humble built 13 new gas plants and expanded 14 existing ones in Texas and Louisiana to remove additional liquids from natural gas to supply this rapidly growing business.

Humble also broadened activities in two other forms of energy: coal and uranium.

In early 1969 a Humble subsidiary, The Carter Oil Company, which holds large bituminous coal reserves in Illinois and the Rocky Mountain area, signed a long-term sales contract with Commonwealth Edison Company of Chicago. The contract calls for delivery of about three million tons of coal annually. Work was begun to develop an underground mine at Carlinville, Illinois, to supply the coal to the utility company.

In evaluating its uranium holdings, Humble determined that a deposit in Live Oak County, Texas, contained more than five million pounds of recoverable uranium oxide, and a contract is being negotiated with a nonaffiliated company for the commercial development of this ore body.

Canada Imperial Oil Limited accelerated its program for the exploration and evaluation of its strong land position covering about 10 million acres in the Mackenzie River Delta of the Canadian Arctic, 300 miles to the east of the Alaska North Slope discovery. Three seismic parties are at work in the region, and the company is drilling one exploratory well on wholly owned acreage, while a second well is being drilled on acreage in which Imperial has a one-third interest. Imperial also continued to develop production in established oil fields in the Rainbow-Zama area of northern Alberta and to explore other areas of Canada, principally in the West.

Imperial, the leading oil marketer in Canada, continued to expand its petroleum product distribution facilities. An important part of its marketing program has been the installation of automotive service centers, which Imperial pioneered in Canada. At year-end 36 of these centers were in operation.

Canada operating data	1968	Change from 1967
	173,000	6.1%
	354,000	2.3%
	395,000	2.9%
	338	12.3%

Latin America In Venezuela, Creole Petroleum Corporation started construction of a fuel oil desulfurization plant at Amuay refinery. Lago Oil & Transport Company, Limited, which processes substantial volumes of Creole crude oil for export, will build a similar plant in Aruba, Netherlands Antilles. These plants were designed

* * *

DEFENDANT'S EXHIBIT 82

UNITED STATES DISTRICT COURT FOR THE DISTRICT OF NEW JERSEY

Civil Action No. 954-64

UNITED STATES OF AMERICA, PLAINTIFF

v.

STANDARD OIL COMPANY (NEW JERSEY) and POTASH COMPANY OF AMERICA, DEFENDANTS

Before the Honorable Robert Shaw

PLAINTIFF'S PROPOSED FINDINGS OF FACT AND CONCLUSIONS OF LAW

FRED D. TURNAGE
NICOLAUS BRUNS, JR.
RICHARD T. COLMAN

Attorneys, Department of Justice
Washington, D. C.

5. Jersey is among the nation's largest industrial corporations possessing enormous financial resources, conducting operations and making investments, world-wide. Included among its operations and investments are substantial investments in the production and sale of fertilizer products. It has grown significantly in recent years due in large measure to a policy of expending capital liberally and acquiring other firms.

5a. Jersey is a large industrial corporation with enormous financial resources, and world-wide operations and investments.

* * * *

5b. Jersey has grown significantly in recent years, due in large measure to a liberal policy of capital expenditure and the acquisition of other firms.

* * * *

5b(2). Jersey's capital expenditures, including amounts spent in searching for oil and gas reserves, have averaged more than $1 billion annually over the decade preceding 1963, and have been primarily responsible for the company's continuing growth. (GX 2).

* * * *

5d(4). Jersey Production Research Company is a wholly-owned subsidiary of Jersey which conducts research in connection with methods for determining and recovering mineral deposits, principally oil. Any non-petroleum mineral deposits which the company discovers are recorded and reported to Jersey. (Rathbone Tr. 839-41).

* * * *

5e(3). The Board Advisory Committee on Investments (BAC) provides assistance to Jersey and its affiliates in evaluating proposed investments, and also initiates studies of investment opportunities. The BAC reports directly to the Board of Directors and maintains contact with Jersey's various departments. (GX 113, Stip. of Fact No. 2, par. 1). The BAC

consists of the chief executives of practically all of Jersey's major staff groups. (Rathbone Tr. 846).

Ordinarily, a project would be presented to both the BAC and the Executive Committee, with the former being the more detailed review. However, an item budgeted at less than $5 million normally would not go to the Executive Committee. (Mangelsdorf Tr. 342-43).

UNITED STATES DISTRICT COURT

FOR THE

DISTRICT OF NEW JERSEY

CIVIL ACTION NO. 954-64

UNITED STATES OF AMERICA,

Plaintiff,

v.

STANDARD OIL COMPANY (NEW JERSEY)
and POTASH COMPANY OF AMERICA,

Defendants.

BEFORE THE HONORABLE ROBERT SHAW

PLAINTIFF'S MEMORANDUM ACCOMPANYING PLAINTIFF'S PROPOSED FINDINGS OF FACT AND CONCLUSIONS OF LAW

FRED D. TURNAGE

NICOLAUS BRUNS, JR.

RICHARD T. COLMAN

Attorneys, Department of Justice
Washington, D. C.

UNITED STATES DISTRICT COURT

FOR THE

DISTRICT OF NEW JERSEY

UNITED STATES OF AMERICA, Plaintiff, v. STANDARD OIL COMPANY (NEW JERSEY) and POTASH COMPANY OF AMERICA, Defendants.	)	CIVIL ACTION NO. 954-64

PLAINTIFF'S MEMORANDUM ACCOMPANYING PLAINTIFF'S PROPOSED FINDINGS OF FACT AND CONCLUSIONS OF LAW

Simultaneously herewith the Plaintiff is filing its proposed findings of fact and conclusions of law which are fully supported by record references. Rather than repeat the factual detail set forth in the proposed findings or set forth again the many references to, and quotations from, the defendants' own documents as was done in Plaintiff's pretrial brief, this memorandum summarizes the plaintiff's factual contentions and relates them to the legislative purpose underlying Section 7 of the Clayton Act and to recent Supreme Court decisions.

Summary of the Case

Pending the outcome of this litigation, Jersey has been enjoined from consummating its contract to acquire PCA's assets. Consummation of the

contract was originally scheduled for October 21, 1964 and would have achieved Jersey's goal of producing and marketing potash. Jersey's interest in the potash business began in about 1960 when it first became interested in becoming a major fertilizer producer. This was consistent with its continuous desire to put its tremendous financial resources to work by making and selling profitable new products to both new markets and to existing markets in which it was then so successfully selling petroleum and related products.

Jersey's production of its by-product natural gas, from which ammonia is made, led it to manufacture anhydrous ammonia for fertilizer use. In turn, this led it into the manufacture and sale of a full line of fertilizers derived from phosphate and potash. Soon it had extensive fertilizer facilities in Central South America and in other foreign countries. In addition, it was actively exploring the possibilities of entry into the fertilizer business in the United States. To supply its huge actual and potential raw material requirements, it sought to develop and acquire potash and phosphate reserves. With this objective, through its Canadian subsidiary, Jersey had already spent between two and three million dollars and proposed to spend an additional one and one-half million dollars, to conduct the exploration and test drilling essential for the ultimate production of potash.

In a nutshell, the Government's case rests on its contention that because Jersey was so motivated to mine and market potash and because it had the resources to satisfy this desire, it would probably have entered into the production and marketing of potash in competition with PCA and

other United States potash producers by internal expansion or by other means had it not made a contract to acquire PCA. Accordingly, the acquisition, if not permanently enjoined, will eliminate Jersey as a potential competitor to PCA and the other United States potash producers. It will also immediately foreclose such other producers from the opportunity of supplying Jersey's subsidiaries with the enormous amounts of potash they require for their fertilizer manufacturing operations.

Argument

The Statutory Purpose of Section 7

H. Rep. 1191 (81st Congress, 1st Session) makes clear that the amendments to Section 7 of the Clayton Act were concerned with the broad problem of the high level of economic concentration in the American economy. Congress viewed with alarm the increasing power in the hands of the largest corporations and since the trend was found to be due in considerable part to the external expansion of business through mergers and acquisitions, principally by large corporations buying out small companies, Congress sought to stem the tide through the anti-merger provisions of the Clayton Act. Thus, the purpose of the 1950 amendments was "to limit future increases in the level of economic concentration resulting from corporate mergers and acquisitions." (S. Rep. 1775, 81st Congress, 2nd Session). Acquisitions beyond the reach of the Sherman Act were to be proscribed and Section 7 was intended to be an effective guard against "economically significant acquisitions."

Congress therefore, prohibited acquisitions where the effect may be substantially to lessen competition in any line of commerce in any section of the country. There was to be no requirement of actuality or certainty in the injury to competition because anticompetitive consequences were intended to be arrested in their incipiency before they developed.

The legislative history shows particular Congressional concern with acquisitions by large corporations and a broad plan of preserving a free enterprise system of decentralized, independent units. The Supreme Court has expressly recognized that in deciding the legality of a merger it must weigh heavily this economic way of life which Congress was trying to preserve and that mergers which offended it were to be blocked. Brown Shoe Co. v. United States, 370 U.S. 294, 333 (1962). Thus, the size of the acquiring company has uniformly been considered a most important and decisive factor in evaluating acquisitions.

The Supreme Court has applied this philosophy in a number of instances to strike down mergers and acquisitions involving large firms or where the competition which might eventually be lessened was solely potential in character. For instance, in United States v. Aluminum Company of America, 377 U.S. 271 (1964), the Supreme Court held that the acquisition of the Rome Cable Corp. by Alcoa violated Section 7 by eliminating actual competition between them in the sale of aluminum wire and cable. Already the leading producer in the field, acquisition by Alcoa of Rome would add but 1.3% to its market share. But "[P]reservation of Rome, rather than its absorption by one of the giants, will keep it 'as an important competitive

factor' . . ." the Court said (at p. 281). In United States v. El Paso Natural Gas Co., 376 U.S. 651 (1964), Pacific Northwest Gas Co. had been unsuccessful in efforts to sell natural gas in California, could not get the gas needed to set up a project and was unable to satisfy the regulatory agencies as to its ability, but yet the Supreme Court held that it was a substantial potential competitor because of its efforts and its interest in the business and the attractiveness of the market. The entry of new firms in a booming market demonstrated the opportunities which were in fact available. On this basis, the Court found the acquisition of Pacific Northwest by El Paso to be in violation of Section 7. Similarly, in United States v. Penn-Olin Chemical Co., (378 U.S. 158 (1964)), the Supreme Court noted that the relevant business was expanding and both Pennsalt and Olin Mathieson were strongly motivated to enter the market independently. Thus, the Court held that their formation of a joint venture to do so eliminated potential competition between them including the potential competition afforded by a firm which may have merely remained a threat to enter at some indefinite future time.

Thus, Section 7 proscribes acquisitions eliminating the threat of eventual competition as well as those eliminating a substantial factor in actual competition. This is particularly so, as indicated above, when the acquisition is being made by a very large corporation.

The Elimination of Potential Competition Between Jersey and PCA.

Here, Jersey, the largest industrial corporation in the world in terms of assets held, has a record of intensive interest and activity looking to the development of its own potash production and manifestly cogent motivation for doing so. The attractive profit opportunities in this growing field, its complementary relationship to fertilizer activities in which Jersey was already becoming an increasingly important world-wide factor, Jersey's need to carry a full line of fertilizer materials for marketing purposes and need for a raw material position to achieve participation in the most profitable part of the business, are all factors which will continue to move Jersey in this direction even if this acquisition is barred. Jersey's desire for captive potash to supply its fertilizer plants cannot justify its elimination by acquisition of one of the leading competitors it would otherwise face in the production and marketing of potash.

Jersey has the means and motive to enter the business of producing and selling potash on a substantial scale without acquiring a large potash producer. Under the cases, no more need be shown to bar this acquisition. But the fact is that Jersey was actively engaging in activities calculated to bring about an entry into the business through self-development. 1/

1/ The Government does not contend that Jersey's efforts to integrate or diversify are unlawful. On the contrary, such efforts increase competition and add to the national resources. But the Government is attacking the means selected by Jersey to grow, i.e. the elimination of the leading independent competitive factor.

The economics of the fertilizer industry were irrevocably drawing Jersey into a potash producing position. This is clearly demonstrated by the company's own documents. Once in the fertilizer business Jersey soon learned it could maximize fertilizer profits by producing potash instead of buying it. It learned that carrying a full line was most desirable from a competitive marketing viewpoint. It found that the potash industry offered great growth possibilities and that potash was a product with vast sales potential which was in no danger of competition from other products. Jersey examined potash sources which could supply its own requirements and took out permits in the area of the richest known potash beds in the world. It pursued a detailed solution mining experiment and conducted an extensive number of studies, surveys of competition and market analyses. Solution mining was, however, temporarily shelved, in part to permit evaluation of the results of solution mining by others but mostly because a larger sized conventional mine would make possible greater profits. But since large scale production could be more easily sold if Jersey had a partner to share the burden, Jersey found acquisition of PCA to have benefits over and above those which would be secured after taking the trouble to develop its own business. Moreover, Jersey found that it would require a delay of four to five years before it could begin producing on its own and by that time it have have to face the competition of several other new entrants as well as the competition of the few established suppliers presently in the business. Acquisition of PCA nicely eliminated this delay and gave Jersey a jump on the other potential producers, and gave it an experienced sales organization and a

market over and above its own growing needs for potash. Use of its checkbook instead of hard, honest work in the market place was a simple way for Jersey to obtain a commanding position in potash overnight.

Jersey was so motivated to become a potash producer that it would have used its checkbook to continue its self-development program, but for the agreement with PCA. It is not necessary to speculate where or exactly when it would have achieved its goal. It had several permits in the Canadian potash fields and may have found it feasible on further exploration to construct a conventional mine or at least revert to the solution mining technique which is now in use by Kalium Chemicals to mine potash in Canada. Two of Jersey's permits were readily adaptable to this method of extraction.

In short, Jersey now seeks to justify its entry into the potash business by acquisition instead of by self-development because the economics are more attractive, marketing problems are dissolved and it can thereby secure a position immediately. The Supreme Court has expressly held that such business reasons do not authorize an acquisition otherwise unlawful. 2/ Indeed, if such reasons permit a firm like Jersey, with all its vast resources, ingenuity, experience and capabilities, to take the easy road then Section 7 can really do nothing to stop the elimination of independent firms from our economy and the concentration of economic power in the hands of the few. Section 7 clearly was intended by Congress, and has been so construed by the Supreme Court, to forbid by acquisition and merger the elimination of competition which would otherwise probably have existed, such as that between

2/ United States v. Philadelphia National Bank et al, 374 U.S. 321, 370-371 (1963).

Jersey and PCA.

Vertical Foreclosure Resulting from the Acquisition, If Consummated.

This acquisition also violates Section 7 in that it deprives rivals of PCA from the opportunity of supplying the substantial market represented by the potash needs of Jersey's fertilizer plants. The primary vice of a vertical merger or other arrangement tying a customer to a supplier is that by foreclosing the competitors of either party from a segment of the market otherwise open to them, the arrangement may act as a clog on competition which deprives rivals of a fair opportunity to compete. (Brown Shoe Co. v. United States, supra, at 324). Relying upon the testimony of Brown's President that Brown intended to supply shoes to Kinney, the Court found the results of the acquisition of Kinney by Brown to be analogous to a tying clause and observed that "such an arrangement is inherently anticompetitive" and "can rarely be harmonized with the strictures of the antitrust laws." Thus, the Court said, competition may be substantially lessened "although only a relatively small amount of commerce is affected."

In Brown Shoe the market represented by Kinney's shoe purchases aggregated 1.2% of national shoe sales and the foreclosure at the time of the trial of the action was one-tenth of one percent of the market but the Court passed over this fact with perfunctory consideration and held that since Brown was one of the leading manufacturers of shoes and Kinney, the largest independent chain of family shoe stores, no merger between a producer and independent retailer in the shoe industry could involve a larger potential

market foreclosure. In International Salt Co. v. United States, 332 U.S. 392 (1947), the volume of sales foreclosed by the tie-in clause totalled only about $500,000 and the arrangement was held illegal because this amount of commerce was not insubstantial. Other cases under Section 7 where the vertical foreclosure from an acquisition or merger involved relatively small amounts of commerce but were held to violate the Clayton Act were, for example, United States v. du Pont de Nemours, 353 U.S. 586 (1957), in which du Pont's sales to General Motors comprised but 1.6% of the total market for the type of fabric used by the automobile industry. Because General Motors accounted for almost half of the auto industry's sales its requirements for automotive fabrics must have been substantial, the Court said, and since du Pont was GM's largest supplier, du Pont's ownership of 23% of GM stock resulted in a substantial lessening of competition. In United States v. Bethlehem Steel Corp. et al.,(168 F. Supp. 576 (S.D.N.Y. 1958)), the Court held that Youngstown, a purchaser of wire rope, would probably become a captive market for Bethlehem. In holding that the market represented by Youngstown was substantial and its acquisition by Bethlehem would substantially lessen competition, the Court noted that the foreclosure would involve 1.3% of the entire market or 2,585 tons.

In the instant case, PCA is the leading producer of potash in the United States and the second largest in North America. Although other firms have indicated that they propose to become producers (by 1970 or thereabouts), there are but nine companies presently operating mines in the United States and PCA makes 17% of the total potash deliveries in this country. Jersey,

whose contemporaneous documents reflect the intention of obtaining a captive source of supply and whose Board Chairman (as well as the President of the Jersey subsidiary responsible for obtaining potash for Jersey's fertilizer operations) testified that Jersey fully planned to use PCA after the acquisition as a captive supply source, is a substantial purchaser of potash with requirements in excess of those of the largest customers of PCA or Southwest Potash and greater than the production capacity of three of the nine producers. Thus, like Brown Shoe and du Pont, there really could be no vertical foreclosure in this industry of more significance than Jersey's contemplated acquisition of PCA.

To the extent removal of Jersey as an available customer, as a result of acquiring PCA, forecloses suppliers of shipments from United States mines other than PCA, there is a foreclosure of competition in the production and sale of potash in this country.

Nature of the Evidence

The evidence of Jersey's potential competition, its substantial position and its large purchases of potash are contained primarily in documents obtained from the defendants and offered into evidence by the plaintiff. The defendants have stipulated that these documents are authentic and genuine. Those documents which were preserved in the defendants' files were, almost without exception, prepared concurrently with the events they purport to portray, and reflect the intent, acts and policies of the Jersey complex. The inferences fairly drawn from such material have far more reliability than self-serving declarations and reflective testimony which are intended to try to explain

away the history of the past several years. Such is the character of the evidence principally relied upon by the defendants and even that fails in its purpose. For its principal witnesses, the Chairman of Jersey's Board of Directors and the Chairman of the Esso Chemical subsidiary, both testified that Jersey would continue to look for sources of potash to develop if the acquisition of PCA is blocked by this Court and both stated under oath that PCA was to become a captive source of supply thus precluding other suppliers from participating in the market represented by Jersey's purchases. Thus, their testimony in effect corroborates the inferences flowing from the documentary evidence which plaintiff contends demonstrates that the acquisition of PCA by Jersey would result in a violation of the law.

The weight to be accorded documentary evidence of a contemporaneous nature compared to trial exculpations has been noted by the Supreme Court. For example, in United States v. U. S. Gypsum Co., 333 U.S. 364, 396 (1948), a Sherman Act case, the Supreme Court indicated that in the face of contemporaneous documents establishing a *prima facie* case testimony at trial conflicting with the inferences to be drawn therefrom is entitled to little consideration. In United States v. Penn-Olin, *supra*, the Supreme Court again rejected subjective evidence by corporate officials of the defendants disclaiming their potential competitiveness. The Court relied instead on the probabilities suggested by the objective evidence.

CONCLUSION

The Government submits that the acquisition of PCA by Jersey would violate Section 7 of the Clayton Act, as amended.

Respectfully,

FRED D. TURNAGE

NICOLAUS BRUNS, JR.

RICHARD T. COLMAN

Attorneys, Department of Justice
Washington, D. C.

Dated: April 5, 1965

UNITED STATES DISTRICT COURT

NORTHERN DISTRICT OF ILLINOIS

EASTERN DIVISION

UNITED STATES OF AMERICA,	:	
Plaintiff,	:	Civil No. 67 C 1621
-against-	:	FINAL JUDGMENT
PEABODY COAL COMPANY, et al.,	:	
Defendants.	:	

Plaintiff, United States of America, having filed its complaint herein on Sept. 21, 1967, and plaintiff and defendants, by their respective attorneys, having consented to the entry of this Final Judgment without trial or adjudication of any issue of fact or law herein, and without this Final Judgment constituting any evidence or admission by either party hereto with respect to any such issue;

Now, therefore, without any testimony having been taken, without trial or adjudication of or finding on any issue of fact or law, and on consent of the parties hereto, it is hereby

Ordered, adjudged and decreed:

I.

This Court has jurisdiction of the subject matter of this action and of the parties hereto. The complaint states claims upon which relief may be granted under Section 7 of the Clayton Act, 15 U.S.C. § 18.

II.

As used in this Final Judgment:

A. "Peabody" means the defendant Peabody Coal Company, an Illinois corporation, and any other person owned or controlled by defendant Peabody or owned or controlled by any person owning 50% or more of the voting stock of defendant Peabody;

B. "Stock" means capital stock and any other share capital;

C. "Person" means any individual, partnership, corporation, association or other business or legal entity;

D. "Eastern Interior Coal Province" means the bituminous coal field which underlies approximately 67% of the State of Illinois and a substantial portion of south-western Indiana and western Kentucky;

E. "Eastern Interior Coal Province Sales Area" means the area of the State of Illinois, western Indiana, western Kentucky, western Tennessee, eastern Missouri, eastern Iowa, southwestern and central Wisconsin, and south-eastern Minnesota;

F. "Operating Coal Company" means any person operating one or more bituminous coal mines, or selling any bituminous coal, in the eastern interior coal province sales area;

G. "Coal Reserves" means fee ownership of, or leasehold interest in, or rights to mine under royalty arrangements, or options or contracts to acquire, strip or underground bituminous coal reserves located in the eastern interior coal province sales area.

III.

The provisions of this Final Judgment applicable to any defendant shall also be applicable to each of its officers, directors, agents, and employees and to each of its subsidiaries, successors and assigns, and to all other persons in active concert or participation with any of them who receive actual notice of this Final Judgment by personal service or otherwise.

IV.

A. After two years from the date of entry of this Final Judgment, defendant Peabody is enjoined and restrained from having as an officer or director any person who is at the same time an officer or director of Southwestern Illinois Coal Corporation, an Indiana corporation.

B. Defendant Peabody is enjoined and restrained from having as an officer or director any person who is at the same time an officer or director of any other operating coal company. This provision shall not apply to separately organized joint ventures to which defendant Peabody is a party.

V.

Defendant Peabody is enjoined and restrained for a period of ten years from acquiring, except upon prior approval of the plaintiff, (a) any part of the stock of, or any financial or managerial interest in, any operating coal company, or (b) any coal mine located in the eastern interior coal province sales area.

VI.

Defendant Peabody is hereby enjoined and restrained for a period of five years from the date of entry of this Final Judgment from acquiring in any year commencing on said date or the first four anniversaries thereof, more than five million tons of coal reserves from any other operating coal company or companies except upon prior approval of the plaintiff. The swapping or exchange of coal reserves for coal reserves, without any other payment or consideration, shall be disregarded for purposes of this provision.

VII.

A. Defendant Peabody is ordered and directed, within six months after the entry of this Final Judgment, to organize a separate, viable operating coal business (with adequate strip and/or underground coal mine or mines and coal reserves in the eastern interior coal province, mining and processing machinery and equipment and all facilities used in connection therewith, and managerial, supervisory, technical and other personnel and customer accounts) either as a subsidiary corporation or as a separate division of defendant Peabody, and defendant Peabody is further ordered and directed within two years after the date of entry of this Final Judgment to divest itself, absolutely and in good faith, of said coal business and any financial or managerial interest therein, by one of the following methods:

a. Sale thereof as a viable operating business to a purchaser or purchasers approved by the plaintiff, or

b. Sale of all of the stock thereof by one or more sales to the public through an underwriter or underwriters.

B. The operating coal business required to be established and divested by defendant Peabody under Paragraph A hereof shall, at the time of such divestiture, actually be engaged in the production and sale of bituminous coal at the rate of not less than six million tons per annum, and shall have sufficient assets and earning power, and shall have or shall reasonably be expected to be able to obtain sufficient coal reserves for continued production and sale of bituminous coal at said rate of not less than six million tons per year for twenty years.

C. Plaintiff, prior to the final divestiture of said coal business as provided for in the foregoing Paragraph A, shall have opportunity to approve or disapprove of the assets thereof and, in the event of disagreement with defendant Peabody with respect thereto, plaintiff may petition the Court to determine the matter and enter such order as the Court may deem appropriate to insure fulfillment of the above requirements.

VIII.

A. Defendant Peabody shall make known the availability of said coal business for sale by ordinary and usual means for a sale of a business. Defendant Peabody shall furnish bona fide prospective purchasers all necessary information, including pro forma statements, regarding the same and the operation thereof and shall permit them to make such inspections as may be necessary for the above purpose.

B. Defendant Peabody shall not acquire any long-term debt obligation or stock of, or any equity interest in, the purchaser or purchasers of said coal business except on such terms as may be approved by the plaintiff.

C. At the election of the purchaser or purchasers and with the prior approval of the plaintiff, defendant Peabody may lease, rather than sell or transfer absolutely, the coal reserves to be included in the assets of said coal business.

D. Without the prior approval of the plaintiff, none of the stock of said coal business shall knowingly be disposed of to any person who is an officer, director or executive employee of defendant Peabody, any person in which defendant Peabody owns any material amount of stock or other material financial interest or any person beneficially owning or having unrestricted discretionary power to vote common stock of Peabody in excess of two percent of the shares outstanding, except for an institutional investor acting on behalf of its own members, depositors or shareholders or an underwriter or dealer acting as such.

IX.

For the purpose of determining or securing compliance with this Final Judgment and subject to any legally recognized privilege, duly authorized representatives of the Department of Justice shall, upon written request of the Attorney General or the Assistant Attorney General in charge of the Antitrust Division, and on reasonable notice to defendant Peabody made to its principal office, be permitted (1) reasonable access during the office hours of Peabody to all books, ledgers, accounts, correspondence, memoranda and other records and documents in the possession, custody and control of defendant Peabody relating to any of the matters contained in this Final Judgment, and (2) subject to the

reasonable convenience of defendant Peabody, but without restraint or interference from it, to interview officers, directors, agents or employees of defendant Peabody, who may have counsel present, regarding any such matters; and, upon such request, defendant Peabody shall submit such reports in writing to the Department of Justice with respect to the matters contained in this Final Judgment as may from time to time be requested. No information obtained by the means provided in this Section IX shall be divulged by any representative of the Department of Justice to any person other than a duly authorized representative of the Executive Branch of plaintiff, except in the course of legal proceedings in which the Department of Justice is a party for the purpose of determining or securing compliance with this Final Judgment, or as otherwise required by law.

X.

Jurisdiction of this cause is retained by this Court for the purpose of enabling any party to this Final Judgment to apply to this Court at any time for such further orders and directions as may be necessary or appropriate for the modification, termination, construction or carrying out of the provisions of this Final Judgment and for the enforcement of compliance therewith and punishment of violation thereof.

United States District Judge

October 23, 1967

DX 85

INTERFUEL COMPETITION AND CHANGES IN THE COAL INDUSTRY SINCE WORLD WAR II

Report and Statistics by Dr. Bruce C. Netschert

Defendants' Exhibit 85
U.S. v. General Dynamics, et al.

Report

INTERFUEL COMPETITION AND CHANGES IN THE COAL INDUSTRY SINCE WORLD WAR II

by: Dr. Bruce C. Netschert

I. INTERFUEL COMPETITION

A. In the period since World War II coal has been a decreasingly effective competitor in the following markets: railroads, home and building heating, and industrial users of fuel for heat and electricity generation. The railroad market has completely disappeared; the space heating market has declined by 80% or more; and the industrial market, although suffering a lesser decline in absolute terms, has failed to keep pace with the growth of industry. The utility market, as a consequence, is now the mainstay of coal production. These changes, in terms of the markets for all energy, are not new but are a continuation of trends that have continued throughout much of the present century.

This is demonstrated by the attached tables, which show the declines referred to and the net result: a diminished position of coal in the overall energy resource consumption pattern.

B. These national trends and patterns are paralleled in the Midwest. The utility market is predominant, but in this as well as all other markets there is strong competition from the other fuels. Gas and oil, the traditional competitors, have now been joined by nuclear fuel, which will constitute an evermore serious competitor in the coming decade. Other new competitors are pumped storage, and geothermal energy as a source for power generation.

Coal also faces competition from the other fossil fuels in the market for use by industrial and institutional consumers in heating and

self-generation of electricity. Through the technique of "total energy" or on-site generation gas is definitely a competitor and oil may be. Total energy is growing rapidly and constitutes a competitive threat to coal both directly and indirectly (through the elimination of the consumption of power generated by coal-fired central stations).

In sum, the competitive situation within the energy markets as a whole is already more fluid than it has ever been before and will become still more fluid in the future.

The foregoing is demonstrated by the attached tables.

C. Enacted or pending air pollution abatement controls will have an adverse impact on coal during the next 10-20 years due to their effect on interfuel competition and consumption patterns of coal. This stems from (a) the inability to remove inorganic sulfur from coal economically, (b) the added cost of any desulfurization, (c) the added cost of stack gas desulfurization, (d) the added cost of particulate control, (e) the relative shortage, hence higher value of low sulfur coal, and (f) the inevitable increasing stringency of air pollution regulation over the coming decades.

This will be supported by the general knowledge of the witness and reference to the testimony of other witnesses.

D. In sum, competition among coal producers cannot be considered except within the context of interfuel competition.

II. STRUCTURAL CHANGES IN THE POST-WORLD WAR II PERIOD

A. Since World War II, the following changes in the production and marketing of coal have occurred.

1. In the patterns of coal consumption and marketing

a. Coal has lost its railroad market and has seen its retail market severely curtailed.

b. The industrial market for coal has failed to keep pace with industrial growth.

c. The utility market has grown uninterruptedly and has, as a consequence, come to be the dominant coal use.

d. As a result of the above changes and of changes in the scale and technology of power generation, the major emphasis in coal marketing has increasingly emphasized large quantity, long-term contracts, and Btu content, chemical and physical characteristics.

2. In labor costs

a. As a result of aggressive union bargaining, wage costs and fringe benefits have increased markedly.

3. In mining technology

a. To offset the increased labor costs, there has been a virtual technological revolution in mining

technology, with the introduction of wholly new techniques, significant improvement in old techniques, and a substantial increase in scale.

4. In productivity

   a. The effect of the technological changes has been to increase productivity (as measured in output per man-day) sufficiently to enable the average F.O.B. mine value of coal to be kept competitive and relatively stable in the face of the general inflation in wholesale prices.

5. In coal preparation procedures

   a. The emphasis on Btu content and on uniform characteristics in the delivered coal due to the changes in electric utility technology and buying practices has led to both more coal preparation and more intensive preparation so as to be able to deliver a high and uniform quality product.

6. In transportation costs

   a. The increased competitive pressure on coal in the utility market has led to increased pressure on the railroads to offer lower rates.

   b. The increased competitive pressure on coal has also generated a major technological innovation in

---railroad transportation, namely, the unit train, which has permitted lower rates.

The foregoing is demonstrated in the attached tables.

B. The effect of the changes listed in (A) above has been to enhance the economies of scale in coal production. Indeed, the producers were forced to turn to these economies in order to remain effective competitors in the energy scene.

C. The increased scale required has, in turn, led to greatly increased capital requirements in the industry. "Mechanization" has involved the substitution of capital for labor but, as machines have become larger and mine capacity has also become larger, there have been economies in the capital requirements.

D. All of the foregoing has led to an increase in the size of mines. This is illustrated in the attached tables.

E. In the past six years, oil companies have acquired significant coal production capability through the acquisition of large coal companies. In addition, several other oil companies have acquired large holdings of coal lands and one of these companies is in the process of establishing coal production in the Midwest. This is indicated in the attached table.

The significance of these moves is that the oil industry has established itself as a major element in coal production, linking, in many instances, under common ownership, energy resources of coal, oil, gas, uranium, oil shale and tar sands.

INDEX TO TABLES AND CHARTS

INDEX TO TABLES AND CHARTS (CONTINUED)

INDEX TO TABLES AND CHARTS
(CONTINUED)

TABLE I
U.S. STEAM COAL* CONSUMPTION: ELECTRIC UTILITY, NON-UTILITY AND TOTAL, 1947-1967

Year	Electric Utilities (1,000 tons)	%	Non-Utility (1,000 tons)	%	Total (1,000 tons) (1) + (3)
	(1)	(2)	(3)	(4)	(5)
1947	86,009	19.50%	355,082	80.50%	441,091
1948	95,620	23.17	316,983	76.82	412,603
1949	80,610	22.75	273,692	77.25	354,302
1950	88,262	25.19	262,095	74.81	350,357
1951	101,898	28.67	253,558	71.33	355,456
1952	103,309	32.17	217,834	67.83	321,143
1953	112,283	35.77	201,641	64.22	313,924
1954	115,235	41.50	162,434	58.50	277,669
1955	140,550	44.47	175,485	55.53	316,035
1956	154,983	47.40	171,962	52.59	326,945
1957	157,398	51.50	148,250	48.50	305,648
1958	152,928	52.71	137,195	47.29	290,123
1959	165,788	57.75	121,287	42.25	287,075
1960	173,882	58.07	125,532	41.92	299,414
1961	179,629	59.77	120,895	40.23	300,524
1962	190,833	60.87	122,679	39.13	313,512
1963	209,038	63.04	122,554	36.95	331,592
1964	223,032	65.15	119,327	34.86	342,359
1965	242,729	66.61	121,656	33.39	364,385
1966	264,202	67.68	126,172	32.32	390,374
1967	271,784	70.02	116,360	29.98	388,144
1968p	294,739	72.23	113,326	27.77	408,065

* Coverage includes bituminous, sub-bituminous and lignite, as in Bureau of Mines statistics.

p - preliminary.

Source: 1947-1962: U.S. Bureau of Mines, Mineral Industry Surveys, Weekly Coal Report No. 2635, March 15, 1968, Table 9, p. 8.

1963-1967: U.S. Bureau of Mines, Mineral Industry Surveys, "Coal -- Bituminous and Lignite in 1967," February 14, 1969, Weekly Coal Report No. 2683, Supplement, Table 60, p. 84.

FIGURE I-A

U.S. STEAM COAL CONSUMPTION: ELECTRIC UTILITY, NON-UTILITY AND TOTAL, 1947-1967

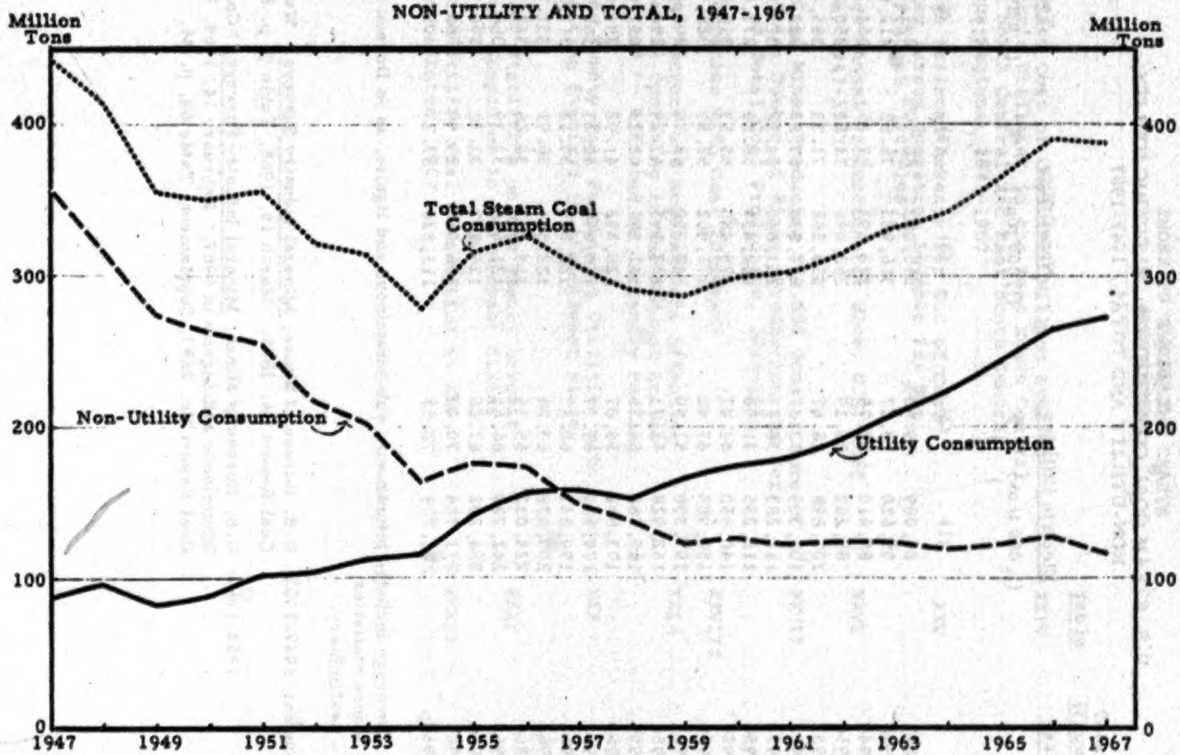


FIGURE I-B

U.S. STEAM COAL CONSUMPTION: PERCENT UTILITY AND PERCENT NON-UTILITY, 1947-1967

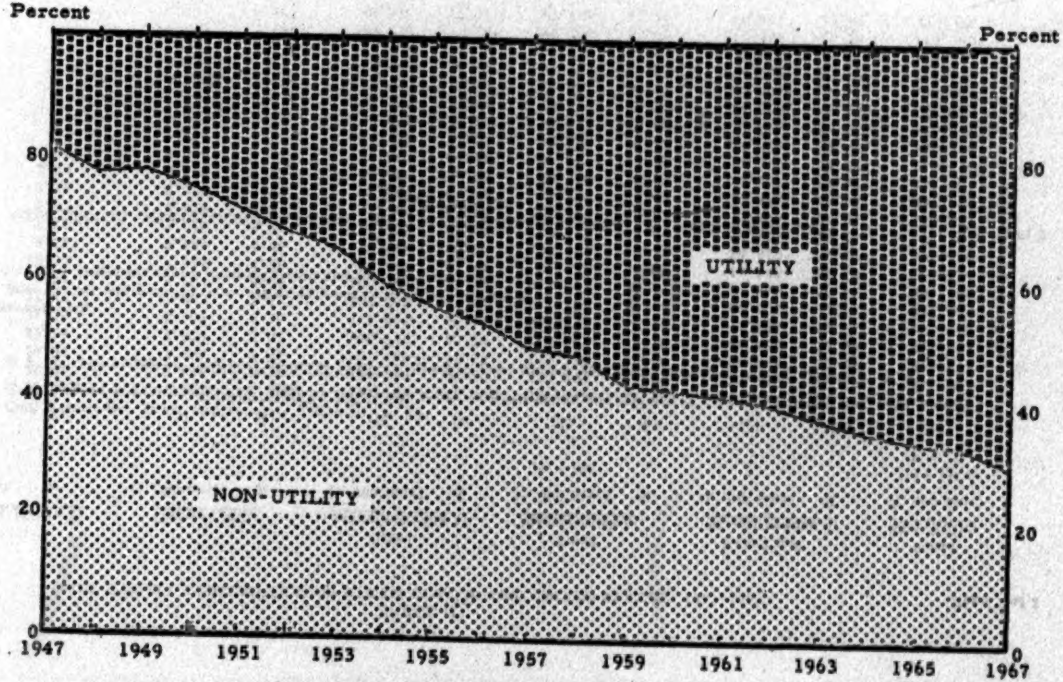


TABLE II

NON-UTILITY CONSUMPTION OF STEAM COAL* IN THE UNITED STATES, 1947-1967

Year	Railroads (Class I)		Cement Mills		Other Manufacturing 1/		Total Manufacturing		Retail and Miscellaneous 2/		Total Non-Utility
	(1,000 tons)	%	(1,000 tons)	%	(1,000 tons)	%	(1,000 tons) (3) + (5)	%	(1,000 tons)	%	(1,000 tons) (1) + (3) + (5) + (9)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1947	109,296	30.78%	7,919	2.23%	138,123	38.90%	146,042	41.13%	99,744	28.09%	355,082
1948	94,838	29.92	8,546	2.70	124,253	39.20	132,799	41.89	89,346	28.19	316,983
1949	68,123	24.89	7,966	2.91	107,158	39.15	115,124	42.06	90,445	33.05	273,692
1950	60,969	23.26	7,923	3.02	106,739	40.73	114,662	43.75	86,464	32.99	262,095
1951	54,005	21.30	8,507	3.36	114,448	45.14	122,955	48.49	76,598	30.21	253,558
1952	37,962	17.43	7,903	3.63	103,269	47.41	111,172	51.04	68,700	31.54	217,834
1953	27,735	13.75	8,167	4.05	103,924	51.54	112,091	55.59	61,815	30.66	201,641
1954	17,370	10.69	7,924	4.88	84,098	51.77	92,022	56.65	53,042	32.65	162,434
1955	15,473	8.82	8,529	4.86	96,964	55.25	105,493	60.12	54,519	31.07	175,485
1956	12,308	7.16	9,026	5.25	100,491	58.44	109,517	63.69	50,137	29.16	171,962
1957	8,401	5.67	8,633	5.82	94,140	63.50	102,773	69.32	37,076	25.01	148,250
1958	3,725	2.72	8,256	6.02	88,640	64.61	96,896	70.63	36,574	26.66	137,195
1959	2,600	2.14	8,510	7.02	80,070	66.02	88,580	73.03	30,107	24.82	121,287
1960	2,101	1.67	8,216	6.54	83,865	66.81	92,081	73.35	31,350	24.97	125,532
1961	3/	-	7,615	6.30	84,775	70.12	92,390	76.42	28,505	23.58	120,895
1962	3/	-	7,719	6.29	86,085	70.17	93,804	76.46	28,875	23.54	122,679
1963	3/	-	8,138	6.64	90,198	73.60	98,336	80.24	24,218	19.76	122,554
1964	3/	-	8,679	7.27	90,322	75.69	99,001	82.97	20,326	17.03	119,327
1965	3/	-	8,873	7.29	93,080	76.51	101,953	83.80	19,703	16.20	121,656
1966	3/	-	9,149	7.25	96,449	76.44	105,598	83.69	20,574	16.31	126,172
1967	3/	-	8,922	7.67	89,872	77.24	98,794	84.90	17,566	15.10	116,360
1968			9,391	8.29	88,294	77.91	97,685	86.20	15,641	13.80	113,326

* Coverage includes bituminous, sub-bituminous and lignite, as in Bureau of Mines statistics.

TABLE II
NON-UTILITY CONSUMPTION OF STEAM COAL IN THE UNITED STATES, 1947-1967 (CONTINUED)

1/ Includes steel and rolling mills and other manufacturing and mining industries.
2/ Includes bunker, lake vessel and foreign, plus retail deliveries to other consumers.
3/ Data collection discontinued.

Source: 1947-1962: U.S. Bureau of Mines, Mineral Industry Surveys, Weekly Coal Report No. 2635, March 15, 1968, Table 9, p. 8.

1963-1967: U.S. Bureau of Mines, Mineral Industry Surveys, "Coal -- Bituminous and Lignite in 1967," February 14, 1969, Weekly Coal Report No. 2683, Supplement, Table 60, p. 84.

FIGURE II

NON-UTILITY CONSUMPTION OF STEAM COAL IN THE UNITED STATES, 1947-1967

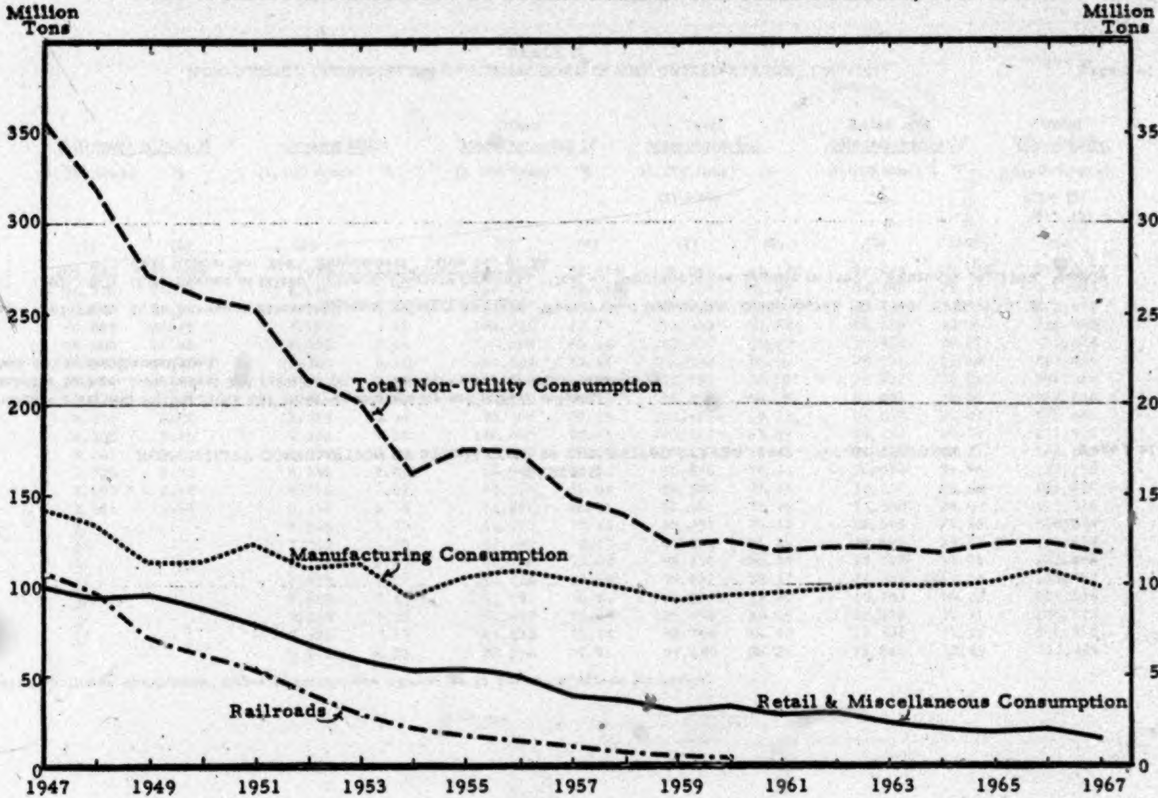


TABLE III

U.S. COAL* CONSUMPTION, TONNAGE AND PERCENTAGE DISTRIBUTION BY CONSUMER CLASS, 1947-1967

Year	Electric Power Utilities (1,000 tons) (1)	% (2)	Railroads (Class I) (1,000 tons) (3)	% (4)	Coke Plants 1/ (1,000 tons) (5)	% (6)	Cement Mills (1,000 tons) (7)	% (8)	Other Manufacturing 2/ (1,000 tons) (9)	% (10)	Retail and Miscellaneous 3/ (1,000 tons) (11)	% (12)	Total Tonnage 4/ (1,000 tons) (13)
1947	86,009	15.76%	109,296	20.02%	104,800	19.20%	7,919	1.45%	138,123	25.30%	99,744	18.27%	545,891
1948	95,620	18.39	94,838	18.24	107,306	20.64	8,546	1.64	124,253	23.90	89,346	17.18	519,909
1949	80,610	18.10	68,123	15.29	91,236	20.48	7,966	1.79	107,158	24.05	90,445	20.30	445,538
1950	88,262	19.43	60,969	13.42	103,845	22.86	7,923	1.74	106,739	23.50	86,464	19.04	454,202
1951	101,898	21.73	54,005	11.52	113,448	24.19	8,507	1.81	114,448	24.41	76,598	16.34	468,904
1952	103,309	24.67	37,962	9.07	97,614	23.31	7,903	1.89	103,269	24.66	68,700	16.41	418,757
1953	112,283	26.31	27,735	6.50	112,874	26.45	8,167	1.91	103,924	24.35	61,815	14.48	426,798
1954	115,235	31.74	17,370	4.78	85,391	23.52	7,924	2.18	84,098	23.16	53,042	14.61	363,060
1955	140,550	33.19	15,473	3.65	107,377	25.36	8,529	2.01	96,964	22.90	54,519	12.88	423,412
1956	154,983	35.80	12,308	2.84	105,913	24.47	9,026	2.09	100,491	23.22	50,137	11.58	432,858
1957	157,398	38.05	8,401	2.03	108,020	26.11	8,633	2.09	94,140	22.76	37,076	8.96	413,668
1958	152,928	41.70	3,725	1.02	76,580	20.88	8,256	2.25	88,640	24.17	36,574	9.97	366,703
1959	165,788	45.27	2,600	0.71	79,181	21.62	8,510	2.32	80,070	21.86	30,107	8.22	366,256
1960	173,882	45.71	2,101	0.55	81,015	21.30	8,216	2.16	83,865	22.04	31,350	8.24	380,429
1961	179,629	47.98	5/	-	73,881	19.73	7,615	2.03	84,775	22.64	28,505	7.61	374,405
1962	190,833	49.21	5/	-	74,262	19.15	7,719	1.99	86,085	22.20	28,875	7.45	387,774
1963	209,038	51.08	5/	-	77,633	18.97	8,138	1.99	90,198	22.04	24,218	5.92	409,225
1964	223,032	51.73	5/	-	88,757	20.59	8,679	2.01	90,322	20.95	20,326	4.71	431,116
1965	242,729	52.86	5/	-	94,779	20.64	8,873	1.93	93,080	20.27	19,703	4.29	459,164
1966	264,202	54.33	5/	-	95,892	19.72	9,149	1.88	96,449	19.83	20,574	4.23	486,266
1967	271,784	56.57	5/	-	92,272	19.21	8,922	1.86	89,872	18.71	17,566	3.66	480,416
1968	294,739	59.09			90,765	18.20	9,391	1.88	88,294	17.70	15,641	3.14	498,830

* Coverage includes bituminous, sub-bituminous and lignite, as in Bureau of Mines statistics.

1/ Includes oven and beehive coke plants.
2/ Includes steel and rolling mills and other manufacturing and mining industries.

U.S. COAL* CONSUMPTION, TONNAGE AND PERCENTAGE DISTRIBUTION
BY CONSUMER CLASS, 1947-1967 (CONTINUED)

3/ Includes bunker, lake vessel, and foreign, plus retail deliveries to other consumers.
4/ Approximates total consumption.
5/ Data collection discontinued.

Source: 1947-1962: U S Bureau of Mines, Mineral Industry Surveys, Weekly Coal Report No. 2635, March 15, 1968, Table 9, p. 8.
1963-1967: U.S Bureau of Mines, Mineral Industry Surveys, "Coal -- Bituminous and Lignite in 1967," February 14, 1969, Weekly Coal Report No. 2683, Supplement, Table 60, p. 84.

TABLE IV
ENERGY RESOURCE CONSUMPTION IN THE UNITED STATES, PERCENTAGE BY SOURCE, 1947-1967

Year	Coal*	Anthracite	Total Coal (1) + (2)	Oil 1/	Gas 2/	Hydropower	Nuclear
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1947	43.5	3.7	47.2	32.9	15.5	4.4	-
1948	40.1	3.8	43.9	35.1	16.6	4.4	-
1949	36.9	3.0	39.9	36.3	18.8	5.0	-
1950	34.8	3.0	37.8	37.2	20.3	4.7	-
1951	33.3	2.5	35.8	37.9	22.0	4.3	-
1952	30.0	2.4	32.4	39.4	23.8	4.4	-
1953	29.7	1.9	31.6	40.0	24.3	4.1	-
1954	26.2	1.9	28.1	41.5	26.3	4.1	-
1955	27.8	1.5	29.3	40.8	26.1	3.8	-
1956	27.0	1.4	28.4	41.5	26.3	3.8	-
1957	25.8	1.3	27.1	41.4	27.8	3.7	-
1958	23.1	1.2	24.3	42.0	29.5	4.2	-
1959	22.1	1.1	23.2	42.2	30.7	3.9	-
1960	22.2	1.0	23.2	41.6	31.6	3.6	-
1961	21.5	0.9	22.4	41.6	32.3	3.6	0.1
1962	21.3	0.8	22.1	41.4	32.7	3.7	0.1
1963	21.6	0.7	22.3	40.7	33.4	3.5	0.1
1964	21.9	0.7	22.6	40.0	33.7	3.6	0.1
1965	22.4	0.6	23.0	39.7	33.4	3.8	0.1
1966	22.4	0.5	22.9	39.4	34.0	3.6	0.1
1967p	21.4	0.5	21.9	39.3	34.7	4.0	0.1
1968p	21.0	0.4	21.4	40.1	34.7	3.7	0.1

* Coverage includes bituminous, sub-bituminous and lignite, as in Bureau of Mines statistics.

p - preliminary.

1/ Includes crude petroleum and imported petroleum products.

2/ Includes natural gas liquids and dry natural gas.

Source: U.S. Bureau of Mines, Minerals Yearbook, 1963, 1964, 1966 and 1967 (e.g., Table 8, p. 24, Volume I-II, 1967).

U.S. Department of the Interior, News Release, "Nation's Energy Consumption Hits New All-Time High," March 9, 1969, Table 2 and Table 5.

FIGURE III

ENERGY RESOURCE CONSUMPTION IN THE UNITED STATES,
PERCENTAGE BY SOURCE, 1947-1967

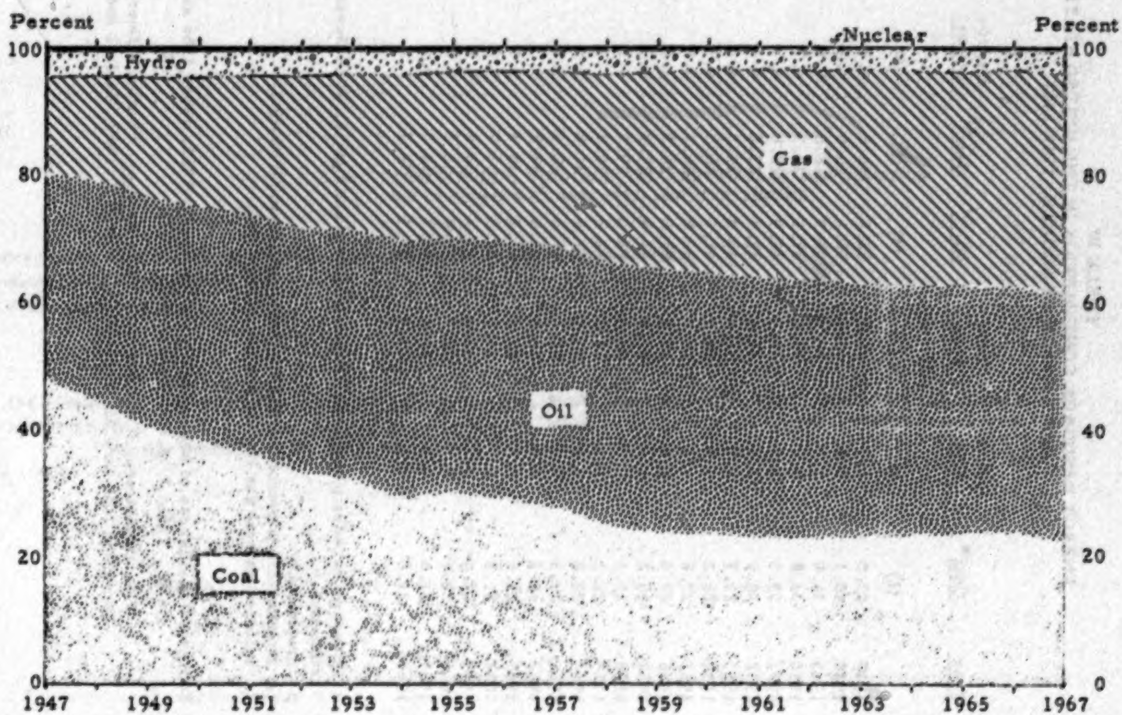


TABLE V
ENERGY RESOURCE CONSUMPTION IN THE UNITED STATES,
PERCENTAGE BY SOURCE, 1920-1967

Year	Coal*	Anthracite	Total Coal (1) + (2)	Oil 1/	Gas 2/	Hydro-power	Nuclear
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1920	67.4%	11.0%	78.4%	13.3%	4.4%	3.9%	- %
1921	62.6	12.7	75.3	16.3	4.4	4.0	-
1922	65.0	8.4	73.4	17.8	4.9	3.9	-
1923	62.7	10.2	72.9	18.6	5.2	3.3	-
1924	62.0	10.0	72.0	18.4	6.2	3.4	-
1925	62.6	7.8	70.4	19.9	6.4	3.3	-
1926	62.0	8.7	70.7	19.3	6.6	3.4	-
1927	60.0	8.7	68.7	20.0	7.5	3.8	-
1928	58.4	8.4	66.8	21.2	8.0	4.0	-
1929	57.3	7.6	64.9	22.3	9.2	3.6	-
1930	53.5	7.7	61.2	25.4	9.9	3.5	-
1931	51.8	7.9	59.7	26.4	10.2	3.7	-
1932	49.1	7.8	56.9	28.0	10.7	4.4	-
1933	49.2	7.5	56.7	28.6	10.4	4.3	-
1934	50.2	7.9	58.1	26.8	11.1	4.0	-
1935	48.9	6.8	55.7	28.8	11.2	4.3	-
1936	49.9	6.3	56.2	28.6	11.3	3.9	-
1937	49.6	5.6	55.2	29.1	11.7	4.0	-
1938	44.3	5.8	50.1	32.5	12.9	4.5	-
1939	45.6	5.9	51.5	31.7	12.8	4.0	-

TABLE V
ENERGY RESOURCE CONSUMPTION IN THE UNITED STATES,
PERCENTAGE BY SOURCE, 1920-1967 (CONTINUED)

Year	Coal *	Anthracite	Total Coal (1) + (2)	Oil 1/	Gas 2/	Hydro-power	Nuclear
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1940	47.2%	5.2%	52.4%	31.4%	12.4%	3.8%	- %
1941	48.4	5.0	53.4	30.8	12.1	3.7	-
1942	50.7	5.2	55.9	27.5	12.4	4.2	-
1943	51.1	4.8	55.9	27.1	12.6	4.4	-
1944	48.5	4.7	53.2	29.1	13.3	4.4	-
1945	46.5	4.2	50.7	30.5	14.1	4.7	-
1946	43.0	4.5	47.5	32.8	15.0	4.7	-
1947	43.5	3.7	47.2	32.9	15.5	4.4	-
1948	40.1	3.8	43.9	35.1	16.6	4.4	-
1949	36.9	3.0	39.9	36.3	18.8	5.0	-
1950	34.8	3.0	37.8	37.2	20.3	4.7	-
1951	33.3	2.5	35.8	37.9	22.0	4.3	-
1952	30.0	2.4	32.4	39.4	23.8	4.4	-
1953	29.7	1.9	31.6	40.0	24.3	4.1	-
1954	26.2	1.9	28.1	41.5	26.3	4.1	-
1955	27.8	1.5	29.3	40.8	26.1	3.8	-
1956	27.0	1.4	28.4	41.5	26.3	3.8	-
1957	25.8	1.3	27.1	41.4	27.8	3.7	-
1958	23.1	1.2	24.3	42.0	29.5	4.2	-
1959	22.1	1.1	23.2	42.2	30.7	3.9	-

TABLE V
ENERGY RESOURCE CONSUMPTION IN THE UNITED STATES,
PERCENTAGE BY SOURCE, 1920-1967 (CONTINUED)

Year	Coal *	Anthracite	Total Coal (1) + (2)	Oil 1/	Gas 2/	Hydro-power	Nuclear
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1960	22.2%	1.0%	23.2%	41.6%	31.6%	3.6%	- %
1961	21.5	0.9	22.4	41.6	32.3	3.6	0.1
1962	21.3	0.8	22.1	41.4	32.7	3.7	0.1
1963	21.6	0.7	22.3	40.7	33.4	3.5	0.1
1964	21.9	0.7	22.6	40.0	33.7	3.6	0.1
1965	22.4	0.6	23.0	39.7	33.4	3.8	0.1
1966	22.4	0.5	22.9	39.4	34.0	3.6	0.1
1967p	21.4	0.5	21.9	39.3	34.7	4.0	0.1
1968	21.0	0.4	21.4	40.1	34.7	3.7	0.1

* Coverage includes bituminous, sub-bituminous and lignite, as in Bureau of Mines statistics.
p = preliminary.

1/ Includes crude petroleum and imported petroleum products.
2/ Includes natural gas liquids and dry natural gas.

Source: 1920-1959: U.S. Bureau of Mines, Minerals Yearbook, 1960, Volume II, Table 6, pp. 9-10.

1960-1966: U.S. Bureau of Mines, Minerals Yearbook, 1964-1967, (e.g., Volume I-II, 1967, Table 8, p. 24).

1967: U.S. Department of the Interior, News Release, "Nation's Energy Consumption Hits New All-Time High," March 9, 1969, Table 2 and Table 5.

FIGURE IV

ENERGY RESOURCE CONSUMPTION IN THE UNITED STATES, PERCENTAGE BY SOURCE, 1920-1967

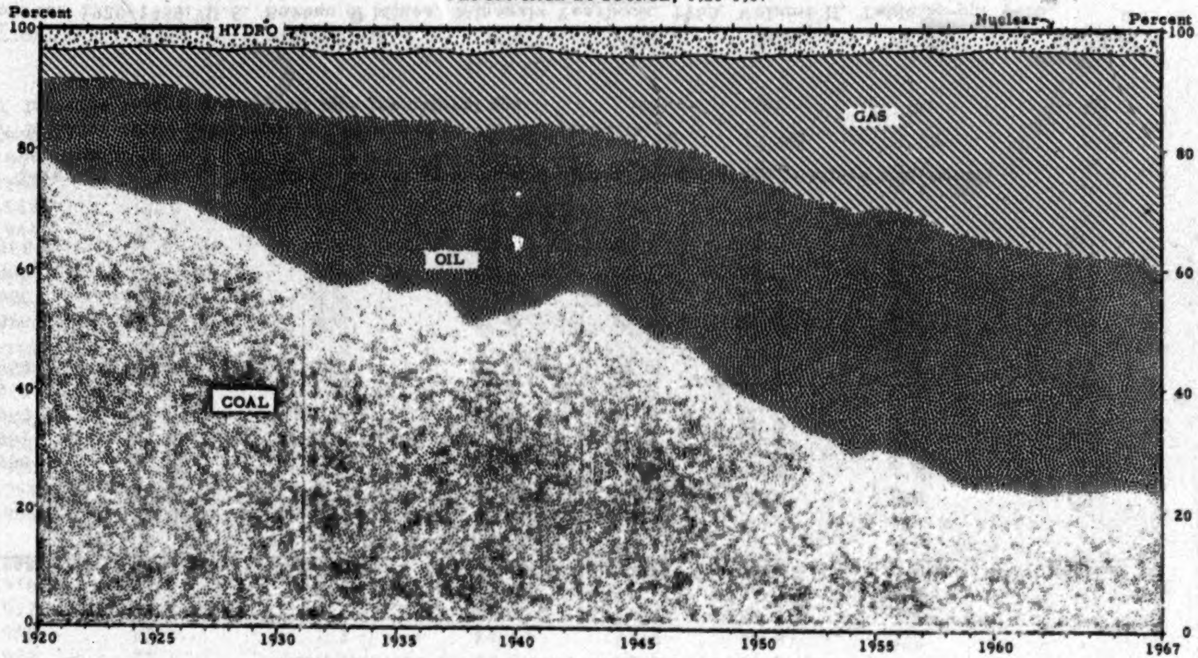


TABLE VI
ELECTRIC UTILITY FOSSIL-FUEL CONSUMPTION
PATTERN IN THE UNITED STATES, 1952-1967

Year	Per Cent of Total Btu Input		
	Coal[a]	Oil	Gas
	(1)	(2)	(3)
1952	67%	10%	23%
1953	66	11	23
1954	65	9	26
1955	68	9	23
1956	70	8	22
1957	69	8	23
1958	68	8	24
1959	66	8	26
1960	66	8	26
1961	65	8	27
1962	65	7	28
1963	65	7	28
1964	65	7	28
1965	66	8	26
1966	65	8	27
1967	64	9	27
1968p	62	9	28

a Coverage includes anthracite, bituminous, sub-bituminous and lignite.

p - preliminary.

Source: National Coal Association, Trends in Electric Utility Industry Experience, 1946-1958, (Washington, D. C.: National Coal Association, 1960), Table 5, p. 96.

National Coal Association, Steam-Electric Plant Factors, 1959-1968 (Washington, D. C.: National Coal Association, 1960-1968), Table 2.

TABLE VII
ELECTRIC UTILITY FOSSIL-FUEL CONSUMPTION
IN THE UNITED STATES, BY CENSUS REGION, 1952-1967

Census Region and Year	Per Cent of Total Btu Input		
	Coal [a]	Oil	Gas
(1)	(2)	(3)	(4)
NEW ENGLAND			
1952	51%	49%	-%
1953	42	58	-
1954	49	48	3
1955	57	39	4
1956	65	31	4
1957	65	31	4
1958	62	33	5
1959	56	39	5
1960	58	37	5
1961	63	34	3
1962	63	33	4
1963	63	33	4
1964	63	33	4
1965	61	36	3
1966	56	42	2
1967	43	55	2
MIDDLE ATLANTIC			
1952	84	11	5
1953	80	13	7
1954	80	13	7
1955	85	10	5
1956	88	8	4
1957	85	8	7
1958	79	12	9
1959	76	14	10
1960	78	14	8
1961	78	14	8
1962	76	15	9
1963	75	15	10
1964	77	15	8
1965	77	16	7
1966	73	21	6
1967	70	23	7

TABLE VII
ELECTRIC UTILITY FOSSIL-FUEL CONSUMPTION
IN THE UNITED STATES, BY CENSUS REGION, 1952-1967 (CONTINUED)

Census Region and Year	Per Cent of Total Btu Input		
	Coal [a]	Oil	Gas
(1)	(2)	(3)	(4)
EAST NORTH CENTRAL			
1952	91%	-%	9%
1953	93	-	7
1954	93	-	7
1955	95	-	5
1956	95	-	5
1957	96	-	4
1958	96	-	4
1959	95	-	5
1960	96	-	4
1961	96	-	4
1962	96	-	4
1963	96	-	4
1964	96	-	4
1965	97	-	3
1966	97	-	3
1967	96	-	4
WEST NORTH CENTRAL			
1952	47	2	51
1953	48	2	50
1954	47	2	51
1955	50	2	48
1956	48	1	51
1957	45	1	54
1958	45	-	55
1959	48	-	52
1960	47	1	52
1961	45	-	55
1962	50	-	50
1963	49	1	50
1964	50	-	50
1965	51	1	48
1966	51	-	49
1967	52	-	48

TABLE VII
ELECTRIC UTILITY FOSSIL-FUEL CONSUMPTION
IN THE UNITED STATES, BY CENSUS REGION, 1952-1967 (CONTINUED)

Census Region and Year	Per Cent of Total Btu Input		
	Coal	Oil	Gas
(1)	(2)	(3)	(4)
SOUTH ATLANTIC			
1952	77%	13%	10%
1953	75	14	11
1954	76	13	11
1955	78	13	9
1956	73	15	12
1957	75	15	10
1958	76	15	9
1959	77	10	13
1960	77	8	15
1961	78	9	13
1962	77	10	13
1963	79	10	11
1964	79	11	10
1965	80	12	8
1966	80	12	8
1967	80	12	8
EAST SOUTH CENTRAL			
1952	70	-	30
1953	73	-	27
1954	79	-	21
1955	87	-	13
1956	90	-	10
1957	90	-	10
1958	91	-	9
1959	91	-	9
1960	92	-	8
1961	92	-	8
1962	92	-	8
1963	92	-	8
1964	92	-	8
1965	92	-	8
1966	91	-	9
1967	89	-	11

TABLE VII
ELECTRIC UTILITY FOSSIL-FUEL CONSUMPTION
IN THE UNITED STATES, BY CENSUS REGION, 1952-1967 (CONTINUED)

Census Region and Year	Per Cent of Total Btu Input		
	Coal [a]	Oil	Gas
(1)	(2)	(3)	(4)
WEST SOUTH CENTRAL			
1952	1%	-%	99%
1953	1	-	99
1954	-	-	100
1955	-	-	100
1956	-	-	100
1957	-	-	100
1958	-	-	100
1959	-	-	100
1960	-	-	100
1961	-	-	100
1962	-	-	100
1963	-	-	100
1964	-	-	100
1965	-	-	100
1966	-	-	100
1967	-	-	100
MOUNTAIN			
1952	29	11	60
1953	27	12	61
1954	22	7	71
1955	25	6	69
1956	22	5	73
1957	19	8	73
1958	22	9	69
1959	27	9	64
1960	26	8	66
1961	30	7	63
1962	31	5	64
1963	40	4	56
1964	45	4	51
1965	49	4	47
1966	51	3	46
1967	52	3	45

TABLE VII
ELECTRIC UTILITY FOSSIL-FUEL CONSUMPTION
IN THE UNITED STATES, BY CENSUS REGION, 1952-1967 (CONTINUED)

Census Region and Year	Per Cent of Total Btu Input		
	Coal *	Oil	Gas
(1)	(2)	(3)	(4)
PACIFIC			
1952	-%	55%	45%
1953	-	52	48
1954	-	29	71
1955	-	40	60
1956	-	48	52
1957	-	46	54
1958	-	33	67
1959	-	32	68
1960	-	32	68
1961	-	27	73
1962	-	21	79
1963	-	19	81
1964	-	17	83
1965	-	19	81
1966	-	18	82
1967	-	16	84

* Coverage includes anthracite, bituminous, sub-bituminous and lignite.

Source: 1952-1958: National Coal Association, Trends in Electric Utility Industry Experience, 1946-1958 (Washington, D. C.: National Coal Association, 1960), Table 5, pp. 76-97.

1959-1967: National Coal Association, Steam-Electric Plant Factors, 1959-1968 (Washington, D. C.: National Coal Association, 1960-1968), Table 2.

TABLE VIII

INSTALLED CONVENTIONAL THERMAL GENERATING CAPACITY AND PER CENT OF TOTAL REPRESENTED BY FACILITIES FOR ALTERNATIVE FUEL USE OTHER THAN COAL[a], EAST NORTH CENTRAL, WEST NORTH CENTRAL, AND EAST SOUTH CENTRAL CENSUS REGIONS, AND MIDWESTERN STATES, 1967

Census Region or State	No. of Plants	Total Capacity	No. of Plants With Facilities For Burning Coal[a] and Oil or Gas	Capacity of Plants With Coal[a] and Oil or Gas Facilities	Capacity of Plants With Coal[a] and Oil or Gas Facilities as a Per Cent of Total Capacity
		(Mw)	(Mw)	(Mw)	(5) ÷ (3)
(1)	(2)	(3)	(4)	(5)	(6)
East North Central	178	47,299.0	47	12,555.6	26.55%
West North Central	184	14,122.8	99	9,384.5	66.45
East South Central	43	21,496.8	8	2,461.7	11.45
Illinois	38	13,250.8	21	8,225.7	62.08
Indiana	32	8,320.0	8	2,896.3	34.81
Wisconsin	25	4,308.7	7	576.4	13.38
Iowa	38	2,300.0	31	2,090.6	90.90
Minnesota	37	2,631.4	26	2,090.8	79.46
Missouri	36	4,034.6	20	2,802.8	69.47
Kentucky	16	5,876.6	3	1,132.2	19.27
Tennessee	6	7,203.7	1	990.0	13.74

[a] Coverage includes bituminous, sub-bituminous and lignite, as in Bureau of Mines statistics.

Source: National Coal Association, Steam-Electric Plant Factors, 1968 Edition, (Washington, D.C.: National Coal Association, 1968), Table 1 and Table 2.

TABLE IX
U.S. THERMAL GENERATING CAPACITY, EXISTING AND PLANNED ADDITIONS AS OF DECEMBER 31, 1968
(Megawatts)

	Fossil Fueled	Nuclear	Total
			(1) + (2)
	(1)	(2)	(3)
Existing Capacity	226,293	2,817	229,110
Planned Additions to Capacity	95,558	62,267	157,825
Total	321,851	65,084	386,935
Percentages			
Of Total Existing Capacity	98.77%	1.23%	100.00%
Of Total Planned Additions to Capacity	60.55	39.45	100.00
Of Total, Existing and Planned	83.18	16.82	100.00

Source: "1969 Annual Statistical Report, Part 2," Electrical World, February 24, 1969, p. 78.

UNITED STATES
ATOMIC ENERGY COMMISSION
WASHINGTON

No. M-84
Tel. 973-3335 or
973-3446

FOR IMMEDIATE RELEASE

NOTE TO EDITORS AND CORRESPONDENTS:

Following is a brief status report on the U. S. civilian nuclear power program:

Status of nuclear power plants, as of March 31, 1969

	kilowatts
13 in operation	2,828,700
46 under construction	35,114,400
32 planned (reactors ordered)	27,902,300
9 planned (reactors not ordered)	8,255,000
Total	74,100,400

During the first quarter of this year there were no announcements by electric utilities of plans to build nuclear power plants or on selection of suppliers for plants previously announced.

During the first quarter of 1968, utilities made known plans for 11 nuclear power plants with a total capacity of 9,680,000 kilowatts. Reactor suppliers have been selected for 8 of these plants.

Attached for your information is a map of the United States showing the location of all present and proposed civilian nuclear power plants for which reactor suppliers have been selected.

\#

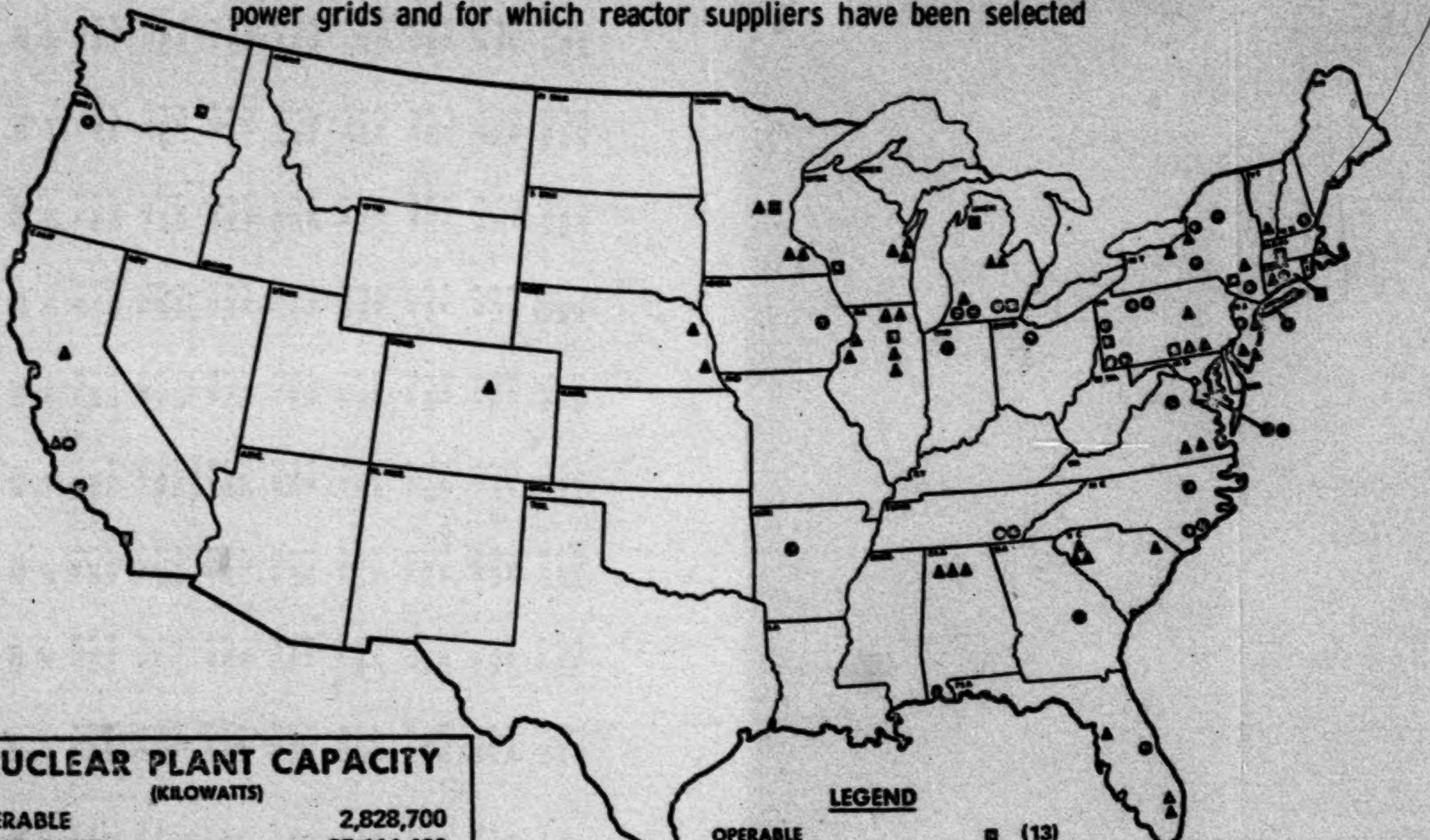
4/10/69

SITE	PLANT NAME	CAPACITY (Kilowatts)	UTILITY	STARTUP
ALABAMA				
Decatur	Browns Ferry Nuclear Power Plant: Unit 1	1,064,500	Tennessee Valley Authority	1970
Decatur	Browns Ferry Nuclear Power Plant: Unit 2	1,064,500	Tennessee Valley Authority	1971
Decatur	Browns Ferry Nuclear Power Plant: Unit 3	1,064,500	Tennessee Valley Authority	1972
ARKANSAS				
London	Arkansas Nuclear One	850,000	Arkansas Power & Light Co.	1972
CALIFORNIA				
Humboldt Bay	Humboldt Bay Power Plant: Unit 3	66,500	Pacific Gas & Electric Co.	1963
San Clemente	San Onofre Nuclear Generating Station	430,000	Southern Calif. Edison and San Diego Gas & Electric Co.	1967
Corral Canyon	Malibu Nuclear Plant: Unit 1	462,000	L. A. Dept of Water & Power	1974
Diablo Canyon	Diablo Canyon Nuclear Power Plant: Unit 1	1,060,000	Pacific Gas & Electric Co.	1972
Diablo Canyon	Diablo Canyon Nuclear Power Plant: Unit 2	1,060,000	Pacific Gas & Electric Co.	1974
Clay Station	Rancho Seco Nuclear Generating Station	800,000	Sacramento Municipal District	1972
COLORADO				
Platteville	Ft. St. Vrain Nuclear Generating Station	330,000	Public Service Co. of Colorado	1972
CONNECTICUT				
Haddam Neck	Conn. Yankee Atomic Power Plant	567,000	Conn. Yankee Atomic Power Co.	1967
Waterford	Millstone Nuclear Power Station: Unit 1	652,100	Northeast Utilities	1969
Waterford	Millstone Nuclear Power Station: Unit 2	828,000	Northeast Utilities	1973
FLORIDA				
Turkey Point	Turkey Point Station: Unit 3	651,500	Florida Power & Light Co.	1970
Turkey Point	Turkey Point Station: Unit 4	651,500	Florida Power & Light Co.	1971
Red Level	Crystal River Plant: Unit 3	825,000	Florida Power Corp.	1972
Ft. Pierce	Hutchinson Island	875,000	Florida Power and Light Co.	1973
GEORGIA				
Baxley	Edwin I. Hatch Nuclear Plant	786,000	Georgia Power Co.	1973
ILLINOIS				
Morris	Dresden Nuclear Power Station: Unit 1	200,000	Commonwealth Edison Co.	1959
Morris	Dresden Nuclear Power Station: Unit 2	715,000	Commonwealth Edison Co.	1969
Morris	Dresden Nuclear Power Station: Unit 3	715,000	Commonwealth Edison Co.	1969
Zion	Zion Station: Unit 1	1,050,000	Commonwealth Edison Co.	1972
Zion	Zion Station: Unit 2	1,050,000	Commonwealth Edison Co.	1973
Cordova	Quad Cities Station: Unit 1	715,000	Comm. Ed. Co.–Ia.–Ill. Gas & Elec. Co.	1970
Cordova	Quad Cities Station: Unit 2	715,000	Comm. Ed. Co.–Ia.–Ill. Gas & Elec. Co.	1971
INDIANA				
Dunes Acres	Bailly Generating Station	515,000	Northern Indiana Public Service Co.	1970's
IOWA				
Cedar Rapids	Duane Arnold Energy Center: Unit 1	545,000	Iowa Electric Light and Power Co	1973
MAINE				
Wiscasset	Maine Yankee Atomic Power Plant	790,000	Maine Yankee Atomic Power Co.	1972
MARYLAND				
Lusby	Calvert Cliffs Nuclear Power Plant: Unit 1	800,000	Baltimore Gas and Electric Co.	1973
Lusby	Calvert Cliffs Nuclear Power Plant: Unit 2	800,000	Baltimore Gas and Electric Co	1974
MASSACHUSETTS				
Rowe	Yankee Nuclear Power Station	175,000	Yankee Atomic Electric Co.	1960
Plymouth	Pilgrim Station	625,000	Boston Edison Co.	1971
MICHIGAN				
Big Rock Point	Big Rock Point Nuclear Plant	70,300	Consumers Power Co.	1962
South Haven	Palisades Nuclear Power Station	700,000	Consumers Power Co.	1969
Lagoona Beach	Enrico Fermi Atomic Power Plant: Unit 1	60,900	Detroit Edison Co.	1963
Lagoona Beach	Enrico Fermi Atomic Power Plant: Unit 2	1,126,000	Detroit Edison Co.	1974
Bridgman	Donald C. Cook Plant: Unit 1	1,054,000	Indiana & Michigan Electric Co.	1972
Bridgman	Donald C. Cook Plant: Unit 2	1,060,000	Indiana & Michigan Electric Co.	1973
Midland	Midland Nuclear Power Plant: Unit 1	533,000	Consumers Power Co.	1974
Midland	Midland Nuclear Power Plant: Unit 2	792,000	Consumers Power Co.	1975
MINNESOTA				
Elk River	Elk River Nuclear Plant	22,000	Rural Cooperative Power Assoc.	1962
Monticello	Monticello Nuclear Generating Plant	545,000	Northern States Power Co.	1970
Red Wing	Prairie Island Nuclear Generating Plant: Unit 1	530,000	Northern States Power Co.	1972
Red Wing	Prairie Island Nuclear Generating Plant: Unit 2	530,000	Northern States Power Co.	1974
NEBRASKA				
Fort Calhoun	Ft. Calhoun Station: Unit 1	457,400	Omaha Public Power District	1971
Brownville	Cooper Nuclear Station	778,000	Consumers Public Power District and Iowa Power and Light Co.	1972
NEW HAMPSHIRE				
Seabrook	Seabrook Nuclear Station	860,000	Public Service Co. of N.H.	1974
NEW JERSEY				
Toms River	Oyster Creek Nuclear Power Plant: Unit 1	515,000	Jersey Central Power & Light Co.	1969
Salem	Salem Nuclear Generating Station: Unit 1	1,050,000	Public Service Gas and Electric Co. of New Jersey	1971
Salem	Salem Nuclear Generating Station: Unit 2	1,050,000	Public Service Gas and Electric Co. of New Jersey	1973
NEW YORK				
Indian Point	Indian Point Station: Unit 1	265,000	Consolidated Edison Co	1962
Indian Point	Indian Point Station: Unit 2	873,000	Consolidated Edison Co	1970
Indian Point	Indian Point Station: Unit 3	965,000	Consolidated Edison Co.	1971
Scriba	Nine Mile Point Nuclear Station	500,000	Niagara Mohawk Power Co.	1969
Rochester	R. E. Ginna Nuclear Power Plant: Unit 1	420,000	Rochester Gas & Electric Co.	1969
Shoreham	Shoreham Nuclear Power Station	800,000	Long Island Lighting Co	1975
Lansing	Bell Station	838,000	New York State Electric & Gas Co	1973
*		1,115,000	Consolidated Edison Co.-Orange and Rockland Utilities, Inc.	1973
Scriba	Nine Mile Point Nuclear Station	815,000	Power Authority of State of N.Y.	1973
NORTH CAROLINA				
Southport	Brunswick Steam Electric Plant: Unit 1	821,000	Carolina Power and Light Co.	1973
Southport	Brunswick Steam Electric Plant: Unit 2	821,000	Carolina Power and Light Co.	1974
*		821,000	Carolina Power and Light Co.	1976
OHIO				
Oak Harbor	Davis-Besse Nuclear Power Station	872,000	Toledo Edison-Cleveland Electric Illuminating Co	1974
OREGON				
Rainier	Trojan Station	1,118,000	Portland General Electric Co.	1974
PENNSYLVANIA				
Peach Bottom	Peach Bottom Atomic Power Station: Unit 1	40,000	Philadelphia Electric Co.	1966
Peach Bottom	Peach Bottom Atomic Power Station: Unit 2	1,065,000	Philadelphia Electric Co.	1971
Peach Bottom	Peach Bottom Atomic Power Station: Unit 3	1,065,000	Philadelphia Electric Co.	1973
*		1,065,000	Philadelphia Electric Co.	1975
*		1,065,000	Philadelphia Electric Co.	1977
Shippingport	Shippingport Atomic Power Station: Unit 1	90,000	Duquesne Light Co.	1957
Shippingport	Beaver Valley Power Station: Unit 1	847,000	Duquesne Light Co.–Ohio Edison Co.	1973
Goldsborough	Three Mile Island Nuclear Station: Unit 1	831,000	Metropolitan Edison Co.	1971
Goldsborough	Three Mile Island Nuclear Station: Unit 2	810,000	Metropolitan Edison Co.	1973
*		1,052,000	Pennsylvania Power and Light	1975
*		1,052,000	Pennsylvania Power and Light	1977
SOUTH CAROLINA				
Hartsville	H. B. Robinson S. E. Plant: Unit 2	663,000	Carolina Power & Light Co.	1970
Seneca	Oconee Nuclear Station: Unit 1	841,100	Duke Power Co	1971
Seneca	Oconee Nuclear Station: Unit 2	841,100	Duke Power Co.	1972
Seneca	Oconee Nuclear Station: Unit 3	841,100	Duke Power Co.	1973
TENNESSEE				
Daisy	Sequoyah Nuclear Power Plant: Unit 1	1,124,000	Tennessee Valley Authority	1973
Daisy	Sequoyah Nuclear Power Plant: Unit 2	1,124,000	Tennessee Valley Authority	1973
VERMONT				
Vernon	Vermont Yankee Generating Station	613,900	Vermont Yankee Nuclear Power Corp.-Green Mt. Power Corp.	1970
VIRGINIA				
Gravel Neck	Surry Power Station: Unit 1	783,000	Virginia Electric & Power Co.	1971
Gravel Neck	Surry Power Station: Unit 2	783,000	Virginia Electric & Power Co.	1972
Louisa County	North Anna Power Station: Unit 1	845,000	Virginia Electric & Power Co.	1974
WASHINGTON				
Richland	N-Reactor/WPPSS Steam	790,000	Washington Public Power Supply System	1966
WISCONSIN				
Genoa	LaCrosse Boiling Water Reactor	50,000	Dairyland Power Cooperative	1967
Two Creeks	Point Beach Nuclear Plant: Unit 1	454,000	Wisconsin Michigan Power Co.	1970
Two Creeks	Point Beach Nuclear Plant: Unit 2	454,000	Wisconsin Michigan Power Co.	1971
Carlton	Kewaunee Nuclear Power Plant: Unit 1	527,000	Wisconsin Public Service Co	1972

* Site not selected

NUCLEAR POWER PLANTS IN THE UNITED STATES

The nuclear power plants included in this map are ones whose power is being transmitted or is scheduled to be transmitted over utility electric power grids and for which reactor suppliers have been selected



NUCLEAR PLANT CAPACITY

(KILOWATTS)

OPERABLE		2,828,700
BEING BUILT		35,114,400
PLANNED	REACTORS ORDERED	27,902,300
	REACTORS NOT ORDERED	8,255,000
	TOTAL	74,100,400

ELECTRIC UTILITY CAPACITY BY CONVENTIONAL MEANS AS OF JANUARY 31, 1969: 291,163,554 KILOWATTS

LEGEND

OPERABLE	◘	(13)
BEING BUILT	▲	(46)
*PLANNED (Reactors Ordered)	●	(32)

*9 more plants have been announced for which reactors have not yet been ordered.

U.S.Atomic Energy Commission
March 31, 1969

(over)

TABLE XI
NON-UTILITY CONSUMPTION* OF STEAM COAL,§ NATURAL GAS AND FUEL OIL IN THE MIDWEST STATES, 1957-1967, INDEX BASIS (1957 = 100)

State	Fuel	1957	1958	1959	1960	1961	1962	1963	1964	1965	1966	1967
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Illinois	Coal	100.0	93.5	92.0	82.3	76.8	79.2	76.0	75.1	77.0	73.9	68.1
	Gas	100.0	110.0	122.8	133.7	146.3	156.5	165.5	184.3	200.6	220.6	249.2
	Oil	100.0	131.4	120.3	122.5	122.6	119.5	114.7	105.8	110.8	99.5	115.4
Indiana	Coal	100.0	97.2	96.7	90.3	88.8	88.9	84.7	84.0	83.9	90.8	89.8
	Gas	100.0	107.4	120.7	148.9	168.3	188.9	205.2	232.8	251.5	279.7	306.2
	Oil	100.0	111.2	115.6	124.5	116.1	114.6	114.9	118.6	120.6	113.0	111.4
Iowa	Coal	100.0	96.3	98.4	95.2	85.2	89.0	90.2	83.4	90.6	83.3	76.6
	Gas	100.0	105.7	122.0	124.7	132.8	142.4	149.4	167.5	176.8	160.5	192.1
	Oil	100.0	95.1	112.4	107.3	100.7	99.0	94.9	91.4	88.3	90.4	95.3
Kentucky	Coal	100.0	102.2	88.7	92.5	91.8	91.9	115.2	113.8	109.2	117.4	110.1
	Gas	100.0	104.6	114.3	124.6	126.6	131.7	138.2	146.1	145.1	126.9	162.0
	Oil	100.0	99.9	131.3	98.9	87.9	98.9	89.9	84.8	148.3	174.1	169.7
Minnesota	Coal	100.0	79.1	95.2	116.4	111.2	89.8	98.5	94.9	104.1	90.9	89.6
	Gas	100.0	102.0	112.8	123.9	136.6	156.6	154.1	173.5	187.3	202.3	215.9
	Oil	100.0	93.1	96.0	100.1	89.8	98.1	95.5	92.7	100.4	109.4	98.0
Missouri	Coal	100.0	91.7	91.7	87.9	77.9	75.0	65.1	65.4	63.8	59.3	56.4
	Gas	100.0	107.0	113.1	117.8	122.6	129.8	133.4	141.9	150.5	157.3	161.0
	Oil	100.0	101.0	90.9	88.2	84.5	73.0	74.3	72.4	73.3	74.8	76.5
Tennessee	Coal	100.0	62.4	55.9	56.8	55.8	54.8	59.2	57.4	62.2	64.5	65.1
	Gas	100.0	109.8	111.0	115.3	119.6	124.3	128.1	135.7	144.8	138.9	161.9
	Oil	100.0	95.0	88.7	87.4	90.0	92.2	89.5	80.5	103.9	139.2	190.4
Wisconsin	Coal	100.0	89.9	123.8	123.0	127.2	125.0	119.3	121.2	127.9	124.0	119.1
	Gas	100.0	113.4	138.1	148.9	173.2	208.9	235.3	270.4	314.6	353.2	385.3
	Oil	100.0	130.8	138.0	142.0	145.7	149.1	147.2	143.2	138.5	139.1	168.7

TABLE XI

NON-UTILITY CONSUMPTION * OF STEAM COAL*, NATURAL GAS AND FUEL OIL IN THE MIDWEST STATES, 1957-1967, INDEX BASIS (1957 = 100) (CONTINUED)

* Coverage includes bituminous, sub-bituminous and lignite as in Bureau of Mines statistics.

* Shipments of coal and oil to consumers.

Source: Coal: U.S. Bureau of Mines, Minerals Yearbook, 1962 and 1967.
Gas: U.S. Bureau of Mines, Minerals Yearbook, 1957-1966.
U.S. Bureau of Mines, Mineral Industry Surveys, "Natural Gas Production and Consumption: 1967," September 17, 1968.
Oil: U.S. Bureau of Mines, Mineral Industry Surveys, "Shipments of Fuel Oil and Kerosine," 1957-1967 annual issues.

TABLE XII
TOTAL ENERGY INSTALLATIONS* IN THE MIDWEST STATES
AS OF JANUARY, 1969

	Company (1)	Location (2)	Year (3)	Capacity (Kw) (4)
		ILLINOIS		
1.	O'Hareport Motor Hotel	Chicago	1969	2,000
2.	Caterpillar Tractor Co.	Joliet	1968	8,000
3.	Meadowmart Center	Rockford	1968	1,200
4.	Action Plating Co.	Des Plaines	1967	300
5.	American Oil Co.	Chicago	1965	525
6.	American Oil Co.	Lake Forest	1964	180
7.	Dominic Accorsi	Bartlett	1966	125
8.	Apple River Chemical	East Dubuque	1965	1,500
9.	J.H. Armbruster & Co.	Aurora	1967	120
10.	Bell & Gossett	Morton Grove	N. A.	50
11.	Bergan High School	Peoria	1964	675
12.	Blackberry Poultry Farms	Joliet	1967	200
13.	Cavanagh Foundry	Elgin	1967	300
14.	Celene, Inc.	St. Charles	1967	70
15.	Charles Equipment Co.	Elmhurst	1966	15
16.	Costa High School	Galesburg	1964	250
17.	Decatur Sewage Plant	Decatur	N. A.	325
18.	Deck's Plaza	Geneseo	1967	450
19.	Deco Porcelain	Sycamore	1965	150
20.	DeKalb Suburban Apartments	DeKalb	1965	880
21.	Dixie Square Shopping Center	Harvey	1965	975
22.	Driscoll High School	Addison	1967	500
23.	Edens Executive Center	Wilmette	1966	600
24.	Farmers Grain	Colfax	1965	375
25.	Fehrembacher Oil Co.	Olney	1966	150
26.	Grand Plating Co.	Chicago	1967	200
27.	Hintzsche Feed Mill	Troxel	1960	300
28.	Institute of Gas Technology	Chicago	1963	760
29.	Intercontinental Alloys, Inc.	Joliet	1967	190
30.	Lewis College	Lockport	1965	1,005
31.	Livingston of Chatsworth	Chatsworth	1967	125
32.	Lake Shore Plating	Wilmette	1966	115
33.	Marbon Chemical	Ottawa	1967	2,250
34.	Montini High School	Villa Park	1966	500
35.	Northern Illinois Gas Co.	Aurora	1963	1,240
36.	Northern Illinois Gas Co.	Aurora	1966	150
37.	Northern Illinois Gas Co.	Bellwood	1967	900
38.	Northern Illinois Gas Co.	Crystal Lake	1966	75
39.	Northern Illinois Gas Co.	Elgin	1964	50
40.	Northern Illinois Gas Co.	Elk Grove	1966	75
41.	Northern Illinois Gas Co.	Glen Ellyn	1962	450
42.	Northern Illinois Gas Co.	Glenwood	1965	200
43.	Northern Illinois Gas Co.	Joliet	1966	140
44.	Northern Illinois Gas Co.	LaGrange	1963	75
45.	Northern Illinois Gas Co.	LaGrange	1966	225
46.	Northern Illinois Gas Co.	Naperville	1963	75
47.	Northern Illinois Gas Co.	Palos Heights	1965	65
48.	Northern Illinois Gas Co.	Schaumberg	1964	65
49.	Northern Illinois Gas Co.	Troy Grove	1964	675
50.	Pheasant Run	St. Charles	1963	925

TABLE XII
TOTAL ENERGY INSTALLATIONS * IN THE MIDWEST STATES
AS OF JANUARY, 1969 (CONTINUED)

Company	Location	Year	Capacity (Kw)
(1)	(2)	(3)	(4)
ILLINOIS (CONTINUED)			
51. Watson Oldsmobile	Harvey	1966	25
52. WTAS-FM	Beecher	1966	25
53. Northern Illinois Gas Co.	Anacona	1964	150
54. North Shore Gas Co.	Waukegan	1967	545
55. Patten Tractor	Elmhurst	1966	900
56. Gas Light & Coke Co.	Chicago	1966	4,300
57. Peoples Gas Light & Coke Co.	Chicago	1965	1,000
58. Precision Extrusion	Bensenville	1966	375
59. Process Engineering	Crystal Lake	1967	100
60. Pro Golf	Rosemont	1966	75
61. Quali-Tech Machinery & Engineering	Elk Grove Village	1966	60
62. Radiant Plating	Rosemont	1966	225
63. Rechel Stone	Skokie	1964	225
64. Robt. Frost Jr. High School	Markham	1966	275
65. Sheraton O'Hare Inn	Rosemont	1966	1,400
66. Shappert Engineering	Belvidere	1967	125
67. Siebert & Sons	Chenoa	1962	225
68. Siebert & Sons	Sheldon	1962	75
69. Smith Gas Service Co.	Rockford	1965	50
70. St. Joseph's Health Resort	Wedron	1967	240
71. Tapecoat Mfg. Co.	Evanston	1967	210
72. Tri-State Expressway	Auburn	1966	150
73. Tollway North Office Center	Deerfield	1967	1,225
74. Webtron Corp.	Chicago	1965	30
75. Franciscan Hospital	Rock Island	1968	3,600
TOTAL CAPACITY, ILLINOIS (KW)			46,355
INDIANA			
1. Union Hospital	Terre Haute	1969	2,880
2. Cass County Jr.-Sr. High School	Walton	1967	750
3. Culver School District	Culver	1967	650
4. McAllister Machinery	Indianapolis	1966	350
5. Indiana Oxygen	Indianapolis	1940	160
6. Jefferson High School	Lafayette	1968	600
7. Marion Brick & Tile	Brazil	1965	1,800
8. Paoli Jr.-Sr. High School	Paoli	1967	575
9. Union Hospital	Terre Haute	1968	1,500
10. Whane Supply	Evansville	1966	200
11. South Side Jr. High School	Columbus	1968	650
TOTAL CAPACITY, INDIANA (KW)			10,115

TABLE XII
TOTAL ENERGY INSTALLATIONS* IN THE MIDWEST STATES
AS OF JANUARY, 1969 (CONTINUED)

Company (1)	Location (2)	Year (3)	Capacity (Kw) (4)
IOWA			
1. Green Products	Conrad	1965	625
2. Mercy Hospital	Council Bluffs	N. A.	1,650
3. Hansen's Market	Council Bluffs	1963	290
4. Knoxville Readymix	Knoxville	1966	300
5. Meiners Creamery	Fredericksburg	1963	350
6. Municipal Plant	Council Bluffs	N. A.	150
7. Municipal Plant	Ames	N. A.	150
8. Rockford Brick & Tile	Rockford	1963	175
9. Bourns Electric Mfg. Co.	Ames	1965	1,400
10. Champlin Truck Stop	New Hampton	1966	250
11. Farmers' Co-op	Cresco	1963	375
TOTAL CAPACITY, IOWA (KW)			5,715
KENTUCKY			
1. Jenkins Clinic Hospital	Jenkins	1964	700
2. Turfland Mall	Lexington	1967	4,200
3. Western Kentucky Gas Co.	Owensboro	1966	600
4. Sheffield's Corners	Beaver Dam	1965	150
TOTAL CAPACITY, KENTUCKY (KW)			5,650
MINNESOTA			
1. Superior Plating	Minneapolis	1966	200
2. Computer Time Sharing Corp.	Chaska	1968	250
3. Thunderbird Mall	Virginia	1968	1,700
4. Webb Publishing Co.	Minneapolis	1965	125
5. Anoka Feed & Grain Co.	Anoka	1963	150
6. Minneapolis Honeywell	Minneapolis	1966	200
7. Brady High School	St. Paul	1964	675
8. Minneapolis Gas Co.	Minneapolis	1963	100
9. Williams Hardware	Minneapolis	1965	625
10. Grace High School	Fridley	1965	650
11. Minneapolis Gas Co.	Minneapolis	1964	175
12. Minneapolis Gas Co.	Minneapolis	N. A.	125
13. Vocational High School	Detroit Lakes	1965	450
14. Municipal Plant	Richfield	N. A.	450
15. Todd County Co-op Creamery	Browerville	1962	350
16. Valley Ridge Center	Minneapolis	1963	600
17. Farmers Union Co-op	Inver Grove	1966	450
TOTAL CAPACITY, MINNESOTA (KW)			7,275

TABLE XII
TOTAL ENERGY INSTALLATIONS * IN THE MIDWEST STATES
AS OF JANUARY, 1969 (CONTINUED)

Company (1)	Location (2)	Year (3)	Capacity (Kw) (4)
	MISSOURI		
1. Osteopathic Hospital	Kansas City	1969	2, 300
2. Missouri State Sanitarium	Mount Vernon	1968	1, 000
3. Siegel-Robert Plating Co.	St. Louis	1967	300
4. Pepsi-Cola Bottlers	New Haven	1965	250
5. Acme Plating Co.	St. Louis	1967	300
6. Downtown Ind. Park	Kansas City	1967	600
7. KFVS-TV	Cape Girardeau	1967	475
8. Mark Twain Shopping Center	St. Charles	1968	3, 000
9. Laclede Gas Co.	St. Louis	1968	4, 300
10. Laclede Gas Co.	St. Louis	1966	1, 050
11. Council Plaza	St. Louis	1965	3, 000
12. Midland Brick & Tile	Chillicothe	1964	375
13. Atlas Plastics Co.	Cape Girardeau	1965	1, 350
14. Missouri Delta Hospital	Sikeston	1965	325
TOTAL CAPACITY, MISSOURI (KW)			18, 625
	WISCONSIN		
1. Oscar Meyer, Inc.	Madison	1969	5, 000
2. Wisconsin Southern Gas Co.	Lake Geneva	1968	200
3. Sun Village Apartments	Sun Prairie	1965	500
4. Wisconsin Gas Co.	Milwaukee	1963	2, 550
5. Germantown High School	Germantown	1967	450
6. Spring Mall	Milwaukee	1967	2, 400
TOTAL CAPACITY, WISCONSIN (KW)			11, 100

N. A.: Not Available

* Excludes installations for which applications are listed as continuous duty/standby, municipal generating plants, or applications other than electrical generation.

Source: Total Energy, 1969 Directory and Data Book, Volume 6, No. 1, January, 1969 (San Antonio, Texas: Total Energy Publishing Co., 1969), pp. 41-51.

TABLE XIII
PUMPED STORAGE PROJECTS IN THE UNITED STATES, EXISTING AND PLANNED, AS OF EARLY 1969

System	Project	State	River	Reversible Capacity (Mw)	Year of Initial Operation
(1)	(2)	(3)	(4)	(5)	(6)
EXISTING PROJECTS					
Appalachian Power Co.	Upper Smith Mtn.	Va.	Roanoke	132.0	1965
California Dept. of Water Resources	Oroville	Calif.	Feather	293.2	1968
California Dept. of Water Resources	Thermalito	Calif.	Feather	82.5	1968
Connecticut Light & Power Co.	Rocky River	Conn.	Rocky	7.0	1929
Grand River Dam Authority	Salina *	Okla.	Grand	520.0	1968
Jersey Central Power & Light Co. & Public Service Gas & Electric Co.	Yards Creek *	N.J.	Delaware	337.5	1964
Philadelphia Electric Co., et al.	Muddy Run *	Pa.	Susquehanna	600.0	1967
Power Authority of State of N.Y.	Niagara-Lewiston	N.Y.	Niagara	240.0	1961
Public Service Co. of Colorado	Cabin Creek *	Colo.	South Clear Creek	300.0	1967
Tennessee Valley Authority	Hiwassee	N.C.	Hiwassee	59.5	1956
Union Electric Co.	Taum Sauk *	Mo.	East Fork Black	408.0	1963
U.S. Bureau of Reclamation	Flatiron #3	Colo.	Colorado-Big Thompson	8.5	1954
U.S. Bureau of Reclamation	Senator Wash *	Calif.	Colorado	7.2	1966
U.S. Bureau of Reclamation	O'Neil *	Calif.	Delta Mendota Canal	25.2	1968
U.S. Bureau of Reclamation & California Dept. of Water Resources	San Luis *	Calif.	Cal Aqueduct	424.0	1968
PROJECTS PLANNED, UNDER CONSTRUCTION, OR UNDER CONSIDERATION					
Appalachian Power Co.	Upper Blue Ridge	Va.	New	1,600.0	1975
Arizona Power Authority	Montezuma *	Ariz.	Gila	500.0	1972
Colorado River Water Conservation Dist.	Blair Mtn. *	Colo.	White	525.0	N.A.
Consolidated Edison Co. of N.Y.	Cornwall #1-8 *	N.Y.	Hudson	2,000.0	1975

TABLE XIII

PUMPED STORAGE PROJECTS IN THE UNITED STATES, EXISTING AND PLANNED, AS OF EARLY 1969 (CONTINUED)

System	Project	State	River	Reversible Capacity (Mw)	Year of Initial Operation
(1)	(2)	(3)	(4)	(5)	(6)
PROJECTS PLANNED, UNDER CONSTRUCTION, OR UNDER CONSIDERATION (CONTINUED)					
Consumers Power Co.	Ludington *	Mich.	Lake Michigan	1,872.0	1973
Duke Power Co.	Jocassee	S. C.	Keowee	450.0	1974
Duke Power Co.	Jocassee #2	S. C.	Keowee	2,300.0	N. A.
Georgia Power Co.	Laurens Shoals	Ga.	Oconee	216.0	N. A.
Grand River Dam Authority	Salina #4, 5, & 6 *	Okla.	Grand	129.6	1971
Jersey Central Power & Light Co.	Longwood Valley #1, 2, & 3 *	N. J.	Rockaway	129.0	1971
Jersey Central Power & Light Co. & Public Service Electric & Gas Co.	Tocks Island *	N. J.	Delaware	950.0	N. A.
Los Angeles Dept. of Water & Power & California Dept. of Water Resources	Castaic	Calif.	Aqueduct-Castaic	1,200.0	1972
New England Power Co.	Bear Swamp	Mass.	Deerfield	600.0	1974
Northeast Utilities	Northfield #1, 2 & 3 *	Mass.	Connecticut	750.0	1971
Northeast Utilities	Northfield #4	Mass.	Connecticut	250.0	1972
Pennsylvania Electric Co. & Cleveland Electric Illuminating Co.	Kinzua **	Pa.	Allegheny	330.0	1969
Power Authority of State of N. Y.	Blenheim-Gilboa *	N. Y.	Hudson	1,000.0	1973
Public Utility Dist. #1 of Chelan Co.	Dirty Face Mnt. *	Wash.	Wenatchee	65.0	N. A.
Public Utility Dist #1 of Cowlitz Falls	Cowlitz Falls *	Wash.	Lewis	300.0	N. A.
Salt River Project	Horse Mesa	Ariz.	Salt	70.0	1971
Salt River Project	Mormon Flat	Ariz.	Salt	47.0	1971
Tennessee Valley Authority	Racoon Mnt.	Tenn.	Tennessee	1,400.0	1975
Virginia Electric & Power Co.	Marble Valley *	Va.	Calfpasture	1,000.0	1975
U.S. Army Corps of Engineers	Carters	Ga.	Coosawattee	250.0	1970

TABLE XIII
PUMPED STORAGE PROJECTS IN THE UNITED STATES, EXISTING AND PLANNED, AS OF EARLY 1969 (CONTINUED)

System	Project	State	River	Reversible Capacity (Mw)	Year of Initial Operation
(1)	(2)	(3)	(4)	(5)	(6)
PROJECTS PLANNED, UNDER CONSTRUCTION, OR UNDER CONSIDERATION (CONTINUED)					
U.S. Army Corps of Engineers	De Gray #2	Ark.	Caddo	28.0	1971
U.S. Army Corps of Engineers	Clarence Cannon	Mo.	Salt	27.0	1973
U.S. Army Corps of Engineers	Kaysinger Bluff	Mo.	Osage	160.0	1973
U.S. Bureau of Reclamation	Grand Coulee PP *	Wash.	Columbia	97.0	1971

* "Pure" Pumped Storage Project: Plant which derives its energy from pumped water only.
** Also known as Seneca Project.
N.A.: Not Available.

Source: Federal Power Commission, Hydroelectric Power Resources of the United States, Developed and Undeveloped, January 1, 1968, Table 11, p. 109.

Federal Power Commission, private communication.

Edison Electric Institute, 45th Semi-Annual Electric Power Survey, April, 1969, Appendix I.

Engineering News Record, January 2, 1969, pp. 22-25.

TABLE XIV
U.S. INDUSTRIAL COAL* CONSUMPTION VERSUS PRODUCTION INDEXES -- CEMENT, STEEL AND ALL MANUFACTURING
(1957-1959 = 100)

Year	Index, Industrial Coal * Consumption 1/	Index, All Manufacturing 2/	Index, Steel Production 3/	Index, Cement Production 4/
	(1)	(2)	(3)	(4)
1947	136	66	87	58
1948	130	69	91	64
1949	112	65	80	65
1950	119	76	100	70
1951	128	82	108	76
1952	113	85	96	77
1953	122	93	115	82
1954	96	86	91	84
1955	116	97	120	95
1956	117	100	119	101
1957	115	101	116	94
1958	94	93	88	98
1959	91	106	96	107
1960	94	109	102	101
1961	90	110	101	102
1962	91	119	101	106
1963	96	125	112	111
1964	102	133	131	116
1965	107	145	135	117
1966	109	159	138	120
1967	104	160	131	116
1968	102			

* Coverage includes bituminous, sub-bituminous and lignite, as in Bureau of Mines statistics.

1/ Total of consumption by "manufacturing and mining industries" as listed in source.
2/ Federal Reserve Board Index of Industrial Production, "Manufacturing, Total."
3/ Ingots and castings, all grades.
4/ All types.

TABLE XIV

U.S. INDUSTRIAL COAL[a] CONSUMPTION VERSUS PRODUCTION INDEXES -- CEMENT, STEEL AND ALL MANUFACTURING (CONTINUED)

(1957-1959 = 100)

Source: (Cols. 1, 3, 4): Quantity data in U.S. Bureau of Mines, Minerals Yearbook, 1947-1967.

(Col. 2): 1947-1961: Board of Governors of the Federal Reserve System, Industrial Production, 1957-1959 Base, Table S-151.

1962-1965: Board of Governors of the Federal Reserve System, Division of Research and Statistics, Industrial Production Indexes, 1961-1965, November, 1966, pp. 17-21.

1966 and 1967: Board of Governors of the Federal Reserve System, Federal Reserve Bulletin, December, 1967, p. 2129; December, 1968, p. A-57.

TABLE XV
U.S. ELECTRIC UTILITY COAL* CONSUMPTION VERSUS UTILITY POWER GENERATION, 1947-1967

Year	Utility Coal* Consumption	Utility Power Generation	Index, Coal Consumption	Index, Power Consumption
	(1,000 tons)	(Billion Kwh)	---------(1947 = 100)---------	
	(1)	(2)	(3)	(4)
1947	86,009	256	100	100
1948	95,620	283	111	111
1949	80,610	291	94	114
1950	88,262	329	103	129
1951	101,898	371	118	145
1952	103,309	399	120	156
1953	112,283	443	131	173
1954	115,235	472	134	184
1955	140,550	547	163	214
1956	154,983	601	180	235
1957	157,398	632	183	247
1958	152,928	645	178	252
1959	165,788	710	193	277
1960	173,882	753	202	294
1961	179,629	792	209	309
1962	190,833	852	222	333
1963	209,038	917	243	358
1964	223,032	984	259	384
1965	242,729	1,055	282	412
1966	264,202	1,144	307	447
1967	271,784	1,214	316	474
1968p	294,739	1,327	343	518

* Coverage includes bituminous, sub-bituminous and lignite, as in Bureau of Mines statistics.

p - preliminary.

Source: (Col. 1): U.S. Bureau of Mines, Minerals Yearbook, 1947-1967.

(Col. 2): 1947-1957: U.S. Bureau of the Census, Historical Statistics of the United States, Series S-28, p. 507.

1958-1966: U.S. Bureau of the Census, Statistical Abstract of the United States, 1958-1967.

1967: Federal Power Commission, News Release, No. 16000, March 26, 1969, p. 5.

TABLE XVI

HOURLY EARNINGS IN COAL* PRODUCTION, 1947-1967

Year	Hourly Earnings 1/
(1)	(2)
1947	$ 1.58
1948	1.84
1949	1.88
1950	1.94
1951	2.14
1952	2.22
1953	2.40
1954	2.40
1955	2.47
1956	2.72
1957	2.92
1958	2.93
1959	3.11
1960	3.14
1961	3.12
1962	3.12 2/
1963	3.15 2/
1964	3.30 2/
1965	3.49 2/
1966	3.66 2/
1967	3.75 2/

* Coverage includes bituminous, sub-bituminous and lignite, as in Bureau of Mines statistics.

1/ Production workers only.
2/ 11-month averages.

Source: U.S. Bureau of Labor Statistics, Employment and Earnings Statistics for the United States, 1909-1968, Bulletin No. 1312-6, 1968, p. 21.

n/er

TABLE XVII

U.S. UNDERGROUND COAL* MINING: TOTAL PRODUCTION, MECHANICALLY LOADED AND MINED BY CONTINUOUS MINING MACHINES, 1947-1967 1/

Year	Total Underground Production	Mechanically Loaded 2/	Continuous Mining	Per Cent of Underground Coal: Mechanically Loaded 2/	Per Cent of Underground Coal: Mined by Continuous Mining Machines
	(1,000 tons)				
	(1)	(2)	(3)	(4)	(5)
1947	491,229	298,157	-	60.7%	- %
1948	460,012	295,806	450	64.3	0.1
1949	331,823	222,376	2,600	67.0	0.8
1950	392,844	272,725	4,850	69.4	1.2
1951	415,842	304,051	6,061	73.1	1.5
1952	356,425	268,994	8,215	75.6	2.3
1953	349,551	278,329	11,830	79.6	3.4
1954	289,112	242,970	16,336	84.0	5.7
1955	343,465	290,671	27,460	84.6	8.0
1956	365,774	307,402	39,907	84.0	10.9
1957	360,649	305,737	53,783	84.8	14.9
1958	286,884	243,573	56,373	84.9	19.7
1959	283,434	243,731	65,792	86.0	23.2
1960	284,888	245,786	77,928	86.3	27.4
1961	272,766	235,350	84,321	86.3	30.9
1962	281,266	240,920	90,174	85.7	32.1
1963	302,256	259,241	104,350 3/	85.8	34.5 3/
1964	321,808	281,101	124,677 3/	87.4	38.7 3/
1965	332,661	296,633	141,938 3/	89.2	42.7 3/
1966	338,524	310,281	155,053 3/	91.7	45.8 3/
1967	349,133	329,914	168,803 3/	94.5	48.3 3/
1968p	343,350	326,483	N.A.	95.0	N.A.

* Coverage includes bituminous, sub-bituminous and lignite, as in Bureau of Mines statistics.

p - preliminary.

TABLE XVII
U.S. UNDERGROUND COAL MINING: TOTAL PRODUCTION, MECHANICALLY LOADED AND MINED BY CONTINUOUS MINING MACHINES, 1947-1967 1/
(CONTINUED)

N.A. - Not Available.

1/ Categories not mutually exclusive.
2/ Includes continuous mining.
3/ Includes longwall mining.

Source: (Col. 1, 2, 3): U.S. Bureau of Mines, Minerals Yearbook, 1948-1966, (e.g., Table 36, p. 661, 1966).
U.S. Bureau of Mines, Mineral Industry Surveys, "Coal -- Bituminous and Lignite in 1967," February 14, 1969, Weekly Coal Report No. 2683, Supplement, Table 38, p. 55.

TABLE XVIII
COAL* MINING PRODUCTIVITY BY TYPE OF MINE 1947-1967

Year	Average Tons Per Man Per Day Total	Underground Mines	Strip Mines	Auger Mines
	(1)	(2)	(3)	(4)
1947	6.42	5.49	15.93	1/
1948	6.26	5.31	15.28	1/
1949	6.43	5.42	15.33	1/
1950	6.77	5.75	15.66	1/
1951	7.04	6.08	16.02	1/
1952	7.47	6.37	16.77	20.07
1953	8.17	7.01	17.62	25.30
1954	9.47	7.99	19.64	24.12
1955	9.84	8.28	21.12	22.22
1956	10.28	8.62	21.18	24.85
1957	10.59	8.91	21.64	26.19
1958	11.33	9.38	21.54	28.15
1959	12.22	10.08	22.65	28.77
1960	12.83	10.64	22.93	31.36
1961	13.87	11.41	25.00	30.61
1962	14.72	11.97	26.76	34.61
1963	15.83	12.78	28.69	38.87
1964	16.84	13.74	29.29	42.63
1965	17.52	14.00	31.98	45.85
1966	18.52	14.64	33.57	44.43
1967	19.17	15.08	35.17	46.40

* Coverage includes bituminous, sub-bituminous and lignite, as in Bureau of Mines statistics.

1/ Not reported separately.

Source: U.S. Bureau of Mines, Minerals Yearbook, 1965 and 1966 (e.g., Table 27, p. 648, 1966).

U.S. Bureau of Mines, Mineral Industry Surveys, "Coal -- Bituminous and Lignite in 1967," February 14, 1969, Weekly Coal Report No. 2683, Supplement, Table 29, p. 41.

TABLE XIX
TOTAL U.S. COAL* PRODUCTION, OUTPUT PER MAN-DAY, AND EMPLOYMENT IN COAL PRODUCTION, 1947-1967

Year	Total Production	Index, Production	Output Per Man-Day	Index, Output	Employment 1/	Index, Employment
	(1,000 tons)	(1947 = 100)	(tons)	(1947 = 100)		(1947 = 100)
	(1)	(2)	(3)	(4)	(5)	(6)
1947	630,624	100.00	6.42	100.00	419,182	100.00
1948	599,518	95.07	6.26	97.51	441,631	105.36
1949	437,868	69.43	6.43	100.16	433,698	103.46
1950	516,311	81.87	6.77	105.45	415,582	99.14
1951	533,665	84.62	7.04	109.66	372,897	88.96
1952	466,841	74.03	7.47	116.36	335,217	79.97
1953	457,290	72.51	8.17	127.26	293,106	69.92
1954	391,706	62.11	9.47	147.51	227,397	54.25
1955	464,633	73.68	9.84	153.27	225,093	53.70
1956	500,874	79.43	10.28	160.12	228,163	54.43
1957	492,704	78.13	10.59	164.95	228,635	54.54
1958	410,446	65.09	11.33	176.48	197,402	47.09
1959	412,028	65.34	12.22	190.34	179,636	42.85
1960	415,512	65.89	12.83	199.84	169,400	40.41
1961	402,977	63.90	13.87	216.04	150,474	35.90
1962	422,149	66.94	14.72	229.28	143,822	34.31
1963	458,928	72.77	15.83	246.57	141,646	33.79
1964	486,998	77.22	16.84	262.31	128,698	30.70
1965	512,088	81.20	17.52	272.90	133,732	31.90
1966	533,881	84.66	18.52	288.47	131,752	31.43
1967	552,626	87.63	19.17	298.60	131,523	31.38
1968p	545,000	86.42	N.A.	N.A.	N.A.	N.A.

* Coverage includes bituminous, sub-bituminous and lignite, as in Bureau of Mines statistics.

p - preliminary. N.A. - Not Available.

1/ Average number of men working daily.

Source: 1947-1959: U.S. Bureau of Mines, Minerals Yearbook, 1965, Volume II, Table 6, p. 51-52.

1960-1962: U.S. Bureau of Mines, Minerals Yearbook, 1966, Volume I-II, Table 2, p. 620.

1963-1967: U.S. Bureau of Mines, Mineral Industry Surveys," Coal -- Bituminous and Lignite in 1967," February 14, 1969, Weekly Coal Report No. 2683, Supplement, Table 2, p. 11.

TABLE XX

ANNUAL AVERAGE VALUE PER TON, F.O.B. MINE, OF COAL* PRODUCED IN THE U.S., AND WHOLESALE PRICE INDEX, 1947-1967

Year	Average Value Per Ton (f.o.b. Mine)	Index of Average Value	Wholesale Price Index, Industrial Commodities
		(1957-1959 = 100)	
	(1)	(2)	(3)
1947	$4.16	84.90	75.3
1948	4.99	101.84	81.7
1949	4.88	99.59	80.0
1950	4.84	98.78	82.9
1951	4.92	100.41	91.5
1952	4.90	100.00	89.4
1953	4.92	100.41	90.1
1954	4.52	92.24	90.4
1955	4.50	91.84	92.4
1956	4.82	98.37	96.5
1957	5.08	103.67	99.2
1958	4.86	99.18	99.5
1959	4.77	97.35	101.3
1960	4.69	95.71	101.3
1961	4.58	93.47	100.8
1962	4.48	91.43	100.8
1963	4.39	89.59	100.7
1964	4.45	90.82	101.2
1965	4.44	90.61	102.5
1966	4.54	92.65	104.7
1967	4.62	94.29	106.3
1968p	4.72	96.32	108.7

* Coverage includes bituminous, sub-bituminous and lignite, as in Bureau of Mines statistics.

p - preliminary.

Source: (Col. 1): U.S. Bureau of Mines, Minerals Yearbook, 1965, Table 28, p. 82-83, and 1967, Table 1, p. 331.

U.S. Bureau of Mines, Mineral Industry Surveys, "Coal -- Bituminous and Lignite in 1967," Feb. 14, 1969, Weekly Coal Report No. 2683, Supplement, Table 68, p. 94.

(Col. 3): U.S. Bureau of Labor Statistics, Handbook of Labor Statistics, 1967, Table 113, p. 230.

U.S. Bureau of Labor Statistics, Monthly Labor Review, January, 1969, Table D-3, p. 130.

nera

FIGURE VIII

INDEX OF
ANNUAL AVERAGE VALUE PER TON, F. O. B. MINES, OF COAL PRODUCED IN
THE U. S., AND WHOLESALE PRICE INDEX, 1947-1967
(1957-1959 = 100)

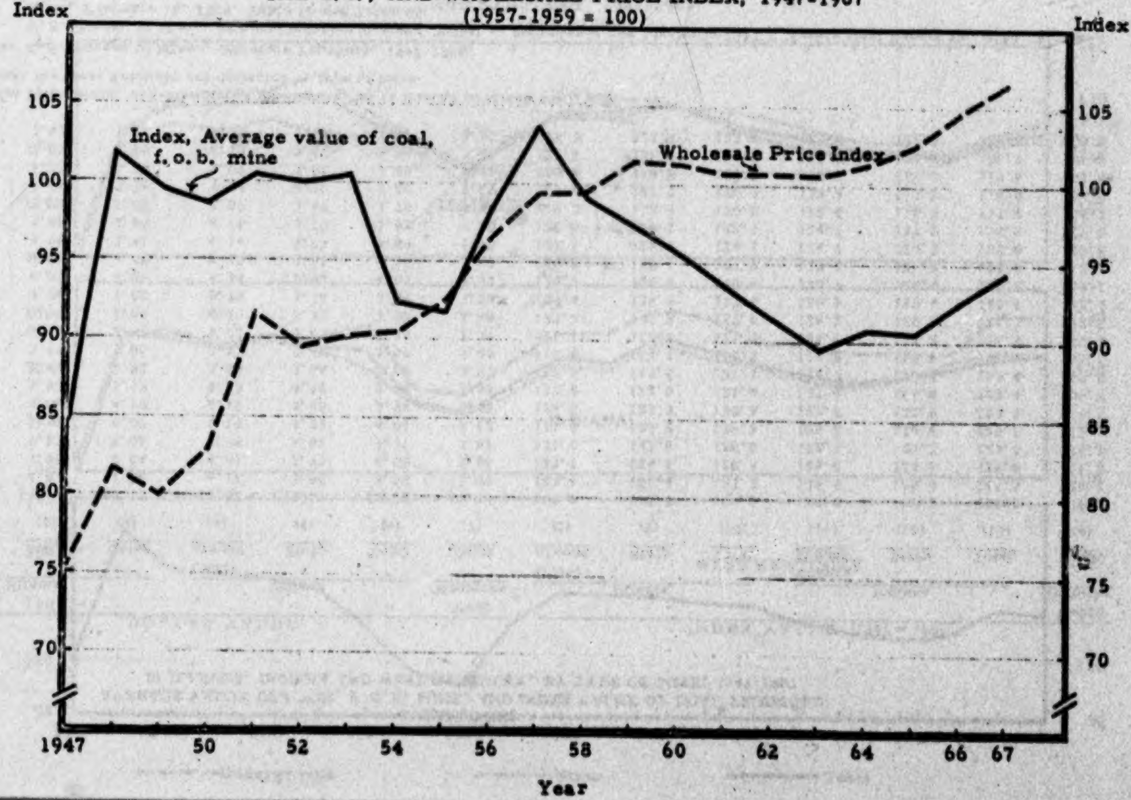


TABLE XXI
AVERAGE VALUE PER TON, F.O.B. MINE, AND INDEX VALUE OF COAL[a] PRODUCED
IN ILLINOIS, INDIANA AND WEST KENTUCKY, BY TYPE OF MINE, 1947-1967

	DOLLAR VALUE							INDEX VALUE (1947 = 100)						
	Illinois			Indiana			West Kentucky*	Illinois			Indiana			West Kentucky*
Year	Under-ground	Strip	Total	Under-ground	Strip	Total	Total	Under-ground	Strip	Total	Under-ground	Strip	Total	Total
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
1947	$3.16	$3.13	$3.15	$3.32	$3.15	$3.22	$3.14	100.0	100.0	100.0	100.0	100.0	100.0	100.0
1948	3.90	3.83	3.88	4.16	3.95	4.04	3.90	123.4	122.4	123.2	125.3	125.4	125.5	124.2
1949	4.10	3.90	4.04	4.21	3.93	4.05	3.66	129.7	124.6	128.3	126.8	124.8	125.8	116.6
1950	4.14	3.87	4.05	4.08	3.88	3.97	3.65	131.0	123.6	128.6	122.9	123.2	123.3	116.2
1951	4.15	3.92	4.07	4.19	3.93	4.04	3.62	131.3	125.2	129.2	126.2	124.8	125.5	115.3
1952	4.24	3.86	4.10	4.15	3.86	3.97	3.55	134.2	123.3	130.2	125.0	122.5	123.3	113.1
1953	4.02	3.82	3.95	4.23	3.76	3.94	3.35	127.2	122.0	125.4	127.4	119.4	122.4	106.7
1954	3.87	3.74	3.82	3.84	3.54	3.65	3.07	122.5	119.5	121.5	115.7	112.4	113.4	97.8
1955	3.71	3.57	3.66	3.81	3.49	3.59	3.00	117.4	114.1	116.2	114.8	110.8	111.5	95.5
1956	3.84	3.84	3.84	4.02	3.63	3.75	3.37	121.5	122.7	121.9	121.1	115.2	116.5	107.3
1957	4.02	3.97	4.00	4.19	3.79	3.92	3.54	127.2	126.8	127.0	126.2	120.3	121.7	112.7
1958	4.09	3.94	4.02	4.20	3.76	3.89	3.53	129.4	125.9	127.6	126.5	119.4	120.8	112.4
1959	4.10	4.01	4.06	4.34	3.92	4.05	3.52	129.7	128.1	128.9	130.7	124.4	125.8	112.1
1960	4.00	4.01	4.00	4.29	3.82	3.96	3.49	126.6	128.1	127.0	129.2	121.3	123.0	111.1
1961	3.87	3.96	3.91	4.14	3.79	3.89	3.48	122.5	126.5	124.1	124.7	120.3	120.8	110.8
1962	3.81	3.90	3.86	4.14	3.70	3.82	3.38	120.6	124.6	122.5	124.7	117.5	118.6	107.6
1963	3.77	3.83	3.80	4.07	3.67	3.78	3.32	119.3	122.4	120.6	122.6	116.5	117.4	105.7
1964	3.76	3.81	3.79	4.09	3.71	3.80	3.29	119.0	121.7	120.3	123.2	117.8	118.0	104.8
1965	3.78	3.72	3.74	4.07	3.81	3.85	3.31	119.6	118.8	118.7	122.6	121.0	119.6	105.4
1966	3.90	3.81	3.85	4.30	3.87	3.92	3.45	123.4	121.7	122.2	129.5	122.9	121.7	109.9
1967	3.96	3.83	3.88	4.31	3.87	3.91	3.42	125.3	122.4	123.2	129.8	122.9	121.4	108.9

[a] Coverage includes bituminous, sub-bituminous and lignite, as in Bureau of Mines statistics.
* Average value data for West Kentucky not collected by type of mine.

Source: 1947-1966: U.S. Bureau of Mines, Minerals Yearbook, 1948-1966.
1967: U.S. Bureau of Mines, Mineral Industry Surveys, "Coal -- Bituminous and Lignite in 1967," Weekly Coal Report No. 2683, Supplement, February 14, 1969, Table 56 and Table 68.

FIGURE IX
INDEX OF AVERAGE VALUE PER TON, F.O.B. MINE, OF UNDERGROUND, STRIP AND TOTAL COAL PRODUCED IN ILLINOIS, INDIANA AND KENTUCKY, 1947-1967
(1947 = 100)

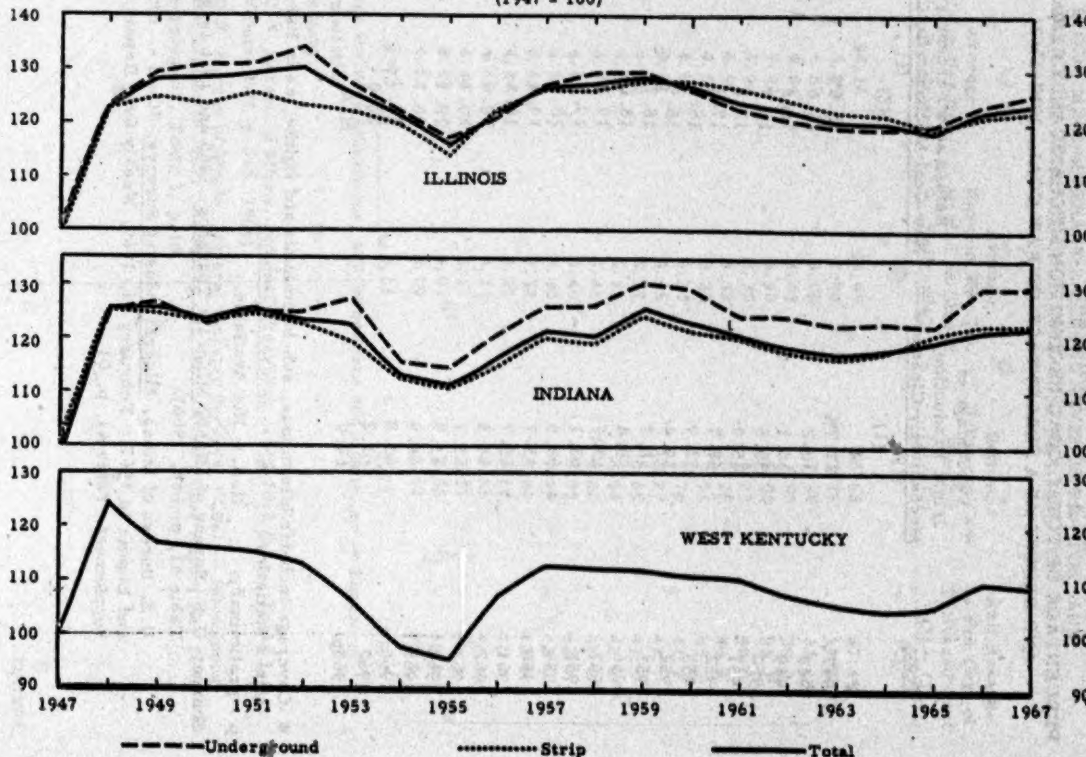


TABLE XXII

PERCENTAGE OF TOTAL COAL* PRODUCTION MECHANICALLY CLEANED, AND REFUSE AS A PERCENTAGE OF RAW COAL, 1947-1967

Year	Percentage of Total Production Mechanically Cleaned	Refuse as a Percentage of Raw Coal Mechanically Cleaned
	(1)	(2)
1947	27.7%	15.6%
1948	30.2	16.0
1949	35.1	16.8
1950	38.5	16.7
1951	45.0	17.2
1952	48.7	17.1
1953	52.9	18.2
1954	59.4	18.9
1955	58.7	18.7
1956	58.4	18.6
1957	61.7	19.3
1958	63.1	19.3
1959	65.5	20.0
1960	65.7	19.3
1961	65.7	19.3
1962	64.3	20.0
1963	63.1	20.1
1964	63.7	20.1
1965	64.9	20.7
1966	63.8	21.7
1967	63.2	22.0
1968p	64.0	N.A.

* Coverage includes bituminous, sub-bituminous and lignite, as in Bureau of Mines statistics.

p - preliminary. N.A. - Not Available.

Source: U.S. Bureau of Mines, Minerals Yearbook, 1965 and 1966 (e.g., Table 41, p. 666, 1966).

U.S. Bureau of Mines, Mineral Industry Surveys, "Coal -- Bituminous and Lignite in 1967," February 14, 1969, Weekly Coal Report No. 2683, Supplement, Table 44, p. 61.

TABLE XXIII
ANNUAL AVERAGE VALUE OF COAL* PER TON, F.O.B. MINE, AVERAGE RAILROAD REVENUE PER TON, AND INDICATED AVERAGE DELIVERED COST PER TON, 1947-1967

Year	Average Value Per Ton, f.o.b. Mine	Average Revenue Per Ton Hauled on Class I Railroads	Indicated Delivered Cost Per Ton (1) + (2)	Rail Revenue as Per Cent of Delivered Cost (2) ÷ (3)
	(1)	(2)	(3)	(4)
1947	$4.16	$2.49	$6.65	37.4%
1948	4.99	2.74	7.73	35.4
1949	4.88	3.00	7.88	38.1%
1950	4.84	3.09	7.93	39.0
1951	4.92	3.16	8.08	39.1
1952	4.90	3.35	8.25	40.6
1953	4.92	3.33	8.25	40.4
1954	4.52	3.23	7.75	41.7
1955	4.50	3.24	7.74	41.9
1956	4.82	3.45	8.27	41.7
1957	5.08	3.57	8.65	41.3
1958	4.86	3.58	8.44	42.4
1959	4.77	3.45	8.22	42.0
1960	4.69	3.40	8.09	42.0
1961	4.58	3.40	7.98	42.6
1962	4.48	3.32	7.80	42.6
1963	4.39	3.21	7.60	42.2
1964	4.45	3.11	7.56	41.1
1965	4.44	3.13	7.57	41.3
1966	4.54	3.01	7.55	39.9
1967	4.62	3.00	7.62	39.4
1968p	4.72	3.01	7.73	38.9

* Coverage includes bituminous, sub-bituminous and lignite, as in Bureau of Mines statistics.

p - preliminary.

Source: U.S Bureau of Mines, Minerals Yearbook, 1948-1966 (e.g., Table 1, Volume I-II, p. 619, 1966).

U.S Bureau of Mines, Mineral Industry Surveys, "Coal -- Bituminous and Lignite in 1967," February 14, 1969, Weekly Coal Report No. 2683, Supplement, Table 1, p. 10.

TABLE XXIV

DELIVERED COST 1/ OF COAL* TO ELECTRIC UTILITIES IN THE EAST NORTH CENTRAL, WEST NORTH CENTRAL AND EAST SOUTH CENTRAL CENSUS REGIONS, 1951-1967

Year	Cents Per Million Btu		
	East North Central	West North Central	East South Central
	(1)	(2)	(3)
1951	25.9 2/	28.4 2/	N.A.
1952	26.0	29.0	20.1
1953	26.1	28.8	20.4
1954	24.9	27.2	19.2
1955	23.9	26.5	18.3
1956	24.6	26.9	18.7
1957	25.8	28.2	19.4
1958	25.8	28.1	19.4
1959	25.6	27.5	19.1
1960	25.3	27.0	19.6
1961	25.0	26.2	19.7
1962	24.3	25.8	19.3
1963	24.2	25.4	19.3
1964	24.0	25.3	18.6
1965	23.7	25.6	18.4
1966	24.0	25.7	18.9
1967	24.3	24.7	19.4

N.A.: Not Available

* Coverage includes bituminous, sub-bituminous and lignite, as in Bureau of Mines statistics.

1/ 1951-1961 - "As consumed."
1962-1967 - "F.O.B. plant."

2/ Regional averages computed by National Coal Association from state totals, not from individual plant data.

Source: 1951-1958: National Coal Association, Trends in Electric Utility Industry Experience, 1946-1958, Table 5.

1959-1967: National Coal Association, Steam-Electric Plant Factors, 1959-1968 Editions, Table 2.

TABLE XXV
AVERAGE RAILROAD REVENUE PER TON OF COAL* HAULED,
AND OPERATING REVENUE PER TON, ALL FREIGHT,
CLASS I RAILROADS, 1947-1967

Year	Average Revenue Per Ton of Coal* Hauled	Revenue Per Ton (All Freight)	Index (1947 = 100) Average Revenue Per Ton of Coal* Hauled	Index (1947 = 100) Revenue Per Ton (All Freight)
	(1)	(2)	(3)	(4)
1947	$2.49	$4.82	100.0	100.0
1948	2.74	5.54	110.0	114.9
1949	3.00	6.02	120.5	124.9
1950	3.09	6.02	124.1	124.9
1951	3.16	6.11	126.9	126.8
1952	3.35	6.64	134.5	137.8
1953	3.33	6.76	133.7	140.2
1954	3.23	6.67	129.7	138.4
1955	3.24	6.40	130.1	132.8
1956	3.45	6.48	138.6	134.4
1957	3.57	6.79	143.4	140.9
1958	3.58	7.12	143.8	147.7
1959	3.45	7.06	138.6	146.5
1960	3.40	6.77	136.5	140.5
1961	3.40	6.80	136.5	141.1
1962	3.32	6.80	133.3	141.1
1963	3.21	6.66	128.9	138.2
1964	3.11	6.58	124.9	136.5
1965	3.13	6.69	125.7	138.8
1966	3.01	6.71	120.9	139.2
1967	3.00	6.77	120.5	140.5
1968p	3.01	7.11	120.9	147.5

* Coverage includes bituminous, sub-bituminous and lignite, as in Bureau of Mines statistics.

p - preliminary.

Source: (Col. 1): U.S. Bureau of Mines, Minerals Yearbook, 1948-1967.

(Col. 2): 1947-1957: Association of American Railroads, Statistics of Railroads of Class I in the United States, Calendar Years 1946-1957, p. 4.

1958-1967: Association of American Railroads, Statistics of Railroads of Class I in the United States, Years 1957-1967, p. 5.

TABLE XXVI

AVERAGE ANNUAL PRODUCTION PER MINE, U.S. COAL[a] MINES, 1947-1967

Year	Thousand Tons: Average Production, All Mines	Thousand Tons: Average Production, Mines Producing 500,000 Tons or More	Thousand Tons: Average Production, 50 Largest Mines	Index Value (1950 = 100): All Mines	Index Value (1950 = 100): Mines Producing 500,000 Tons or More	Index Value (1950 = 100): 50 Largest Mines
	(1)	(2)	(3)	(4)	(5)	(6)
1947	72.5	865	N.A.	132.4	101.9	N.A.
1948	66.0	860	N.A.	120.6	101.3	N.A.
1949	51.2	780	N.A.	93.4	91.9	N.A.
1950	54.8	849	1,376	100.0	100.0	100.0
1951	66.6	856	1,503	131.7	100.8	109.3
1952	64.2	818	1,396	117.2	96.3	101.5
1953	68.5	898	1,606	125.2	105.8	116.7
1954	63.9	911	1,469	116.7	107.3	106.8
1955	59.1	969	1,779	108.0	114.1	129.3
1956	58.8	988	1,815	107.4	116.4	132.0
1957	57.7	976	1,913	105.4	115.0	139.1
1958	49.7	940	1,659	90.7	110.7	120.6
1959	53.4	967	1,766	97.5	113.9	128.4
1960	52.8	1,015	1,882	96.4	119.6	136.8
1961	52.7	1,041	1,908	96.2	122.6	138.7
1962	54.5	1,049	1,964	99.6	123.6	142.8
1963	57.8	1,085	2,111	105.6	127.8	153.5
1964	63.8	1,122	2,242	116.6	132.2	162.9
1965	70.8	1,131	2,397	129.4	133.2	174.3
1966	79.1	1,128	2,495	144.5	132.9	181.4
1967	94.1	1,164	2,718	171.8	137.1	197.6
1968p	94.0	N.A.	2,729	171.5	N.A.	198.3

N.A.: Not Available.

[a] Coverage includes bituminous, sub-bituminous and lignite, as in Bureau of Mines statistics.

p - preliminary.

TABLE XXVI
AVERAGE ANNUAL PRODUCTION PER MINE, U.S. COAL[a] MINES, 1947-1967 (CONTINUED)

Source: (Col. 1): 1947-1966: U.S. Bureau of Mines, Minerals Yearbook, 1947-1966.

1967: U.S. Bureau of Mines, Mineral Industry Surveys, "Coal -- Bituminous and Lignite in 1967," February 14, 1969, Weekly Coal Report No. 2683, Supplement, Table 1, p. 10.

(Col. 2): 1947-1966: U.S. Bureau of Mines, Minerals Yearbook, 1947-1966.

1967: U.S. Bureau of Mines, Mineral Industry Surveys, "Coal -- Bituminous and Lignite in 1967," February 14, 1969, Weekly Coal Report No. 2683, Supplement, Table 14, p. 23.

(Col. 3): Coal Mine Directory - Keystone Coal Buyers Manual, Coal Production in the United States for the Year of 1967, Table 4, p. 4.

TABLE XXVII
U.S. COAL* MINES PRODUCING 500,000 TONS OR MORE PER YEAR: NUMBER OF MINES, PRODUCTION AND PER CENT OF TOTAL COAL* PRODUCTION, 1947-1967

Year	Number of Mines	Production (Million tons)	Per Cent of Total Production
	(1)	(2)	(3)
1947	303	262	41.5%
1948	265	228	38.0
1949	164	128	29.3
1950	218	185	35.9
1951	264	226	42.4
1952	231	189	40.5
1953	226	203	44.4
1954	190	173	44.1
1955	227	220	47.4
1956	246	243	48.6
1952	245	239	48.5
1958	200	188	45.8
1959	212	205	49.9
1960	202	205	49.3
1961	195	203	50.4
1962	204	214	50.6
1963	224	243	52.9
1964	238	267	54.9
1965	259	293	57.2
1966	274	309	57.9
1967	281	327	59.1

* Coverage includes bituminous, sub-bituminous and lignite, as in Bureau of Mines statistics.

Source: 1947-1966: U.S. Bureau of Mines, Minerals Yearbook, 1948-1966 (e.g., Table 12, p. 630, Vol. I-II, 1966).

1967: U.S. Bureau of Mines, Mineral Industry Surveys, "Coal -- Bituminous and Lignite in 1967," February 14, 1969, Weekly Coal Report No. 2683, Supplement, Table 14, p. 23.

TABLE XXVIII
OIL COMPANIES WITH COAL INTERESTS

PART A: OIL COMPANIES WITH COAL SUBSIDIARIES

Oil Company	Coal Subsidiary	Year of Acquisition of Entry	1968 Coal Production (tons)	Per Cent of Total U.S. Coal Production in 1968
(1)	(2)	(3)	(4)	(5)
Gulf Oil Co.	Pittsburg and Midway Coal Mining Co.	1964	9,249,500	1.70%
Continental Oil Co.	Consolidation Coal Co.	1966	59,884,621	10.99
Occidental Petroleum Corp.	Island Creek Coal Co.	1968	32,926,752 1/	6.04
Standard Oil Co. of New Jersey	Monterey Coal Co.	1968	2/	-
Standard Oil Co. of Ohio	Old Ben Coal Co.	1968	9,923,107	1.82
Kerr-McGee Corp.	Kerr-McGee Corp.	1969	3/	-
North American Resources Corp.	Thompson Creek Coal & Coke Corp.	1969	4/	-

PART B: ADDITIONAL OIL COMPANIES WITH COAL HOLDINGS NOT SHOWN IN PART A

Oil Company	Location of Holdings
(1)	(2)
Atlantic Richfield Co.	Colorado
Sinclair Oil Corp.	West of the Mississippi River
Shell Oil Co.	Montana
Sun Oil Co.	Wyoming

TABLE XXVIII
OIL COMPANIES WITH COAL* INTERESTS (CONTINUED)

* Coverage includes bituminous, sub-bituminous and lignite, as in Bureau of Mines statistics.

1/ Includes 7,011,000 tons of Maust Coal Corp., acquired by Island Creek in 1969.
2/ Initial production announced for the fall of 1970.
3/ Initial production undertaken in early 1969.
4/ No production since 1966, but company is reported to be investigating potential markets for subsidiary's reserves.

Source: Part A: (Col. 1, 2 & 3): Moody's Investors Service, Moody's Industrial Manual, 1968 (New York: Moody's Investor's Service, 1968).

Federal Trade Commission, Statistical Report No. 4, "Large Mergers in Manufacturing and Mining, 1948-1968," April 1969.

Company Annual Reports for 1968.

The Wall Street Journal, June 18, 1969, p. 6.

(Col. 4): Coal Age, April, 1969, p. 38.

(Col. 5): Preliminary 1968 production figure (545,000,000 tons) from U.S. Bureau of Mines, Mineral Industry Surveys, Weekly Coal Report No. 2700, June 13, 1969, p. 4.

Part B: Sinclair Oil Corp., Proxy Statement for Special Meeting of Stockholders dated November 29, 1969, p. 19.

Price Waterhouse & Co., Selected Information Requested in Subpoena Duces Tecum Issued by Federal Trade Commission under Date of December 31, 1968 on Behalf of Kennecott Copper Corporation, March 6, 1969.

Coal Mining & Processing, February, 1969, p. 10.

Sun Oil Co., 1968 Annual Report, p. 11.

TABLE XXIX

UTILITY MERGERS AND ACQUISITIONS AFFECTING COMPANIES
OPERATING IN THE MIDWEST STATES, 1955-1969 --
EFFECTED OR CURRENTLY PENDING

A. MERGERS & ACQUISITIONS INVOLVING PRIVATELY-OWNED COMPANIES ONLY

Year Merger	Year Data	MIDWEST COMPANY INVOLVED Name	Total Assets	Gross Operating Revenues	Sales	Coal* Consumption	OTHER COMPANY INVOLVED Name	Total Assets	Gross Operating Revenues	Sales	Coal* Consumption	Also in Midwest
			----($ Million)----		(Million kwh)	(1,000 tons)		----($Million)----		(Million kwh)	(1,000 tons)	
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
1955	1954	American Electric Power (through Ohio Power)	$1,035	$230	16,562	8,642 1/	Central Ohio Light & Power	$ 15	$ 5	246	N. A.	
1955	1954	St. Joseph Light & Power	21	7	276	36 2/	Missouri Service 1/	1 3/	1 4/	13	N. A.	X
1955	1954	Union Electric (through Missouri Power & Light)	448	114	7,036	2,548 1/	Segelhorst Electric	N. A.	N. A.	N. A.	N. A.	X
1956	1955	Interstate Power	63	19	639	230 5/	A. O. Fisher Electric	N. A.	N. A.	N. A.	N. A.	X
1956	1955	Interstate Power	63	19	639	230 5/	Northwestern Illinois Gas & Electric	3	1	55	N. A.	X
1956	1955	Iowa Public Service	92	30	735	93	Sac County Electric 1/	1 3/	**	12	N. A.	X
1956	1955	American Electric Power (through Ohio Power)	1,071	258	20,414	13,050 6/	Seneca Light & Power	N. A.	N. A.	N. A.	N. A.	
1957	1956	American Electric Power (through Ohio Power)	1,159	268	20,721	16,183 6/	Celeryville Mutual Light & Power	N. A.	N. A.	N. A.	N. A.	
1957	1956	Northern States Power	577	139 7/	5,002	1,457	Wisconsin Hydro-Electric	9	2	78	--	X
1958	1957	Union Electric	525	129	7,601	2,674	R. W. Foss Electric	N. A.	N. A.	N. A.	N. A.	X
1960	1959	Iowa Southern Utilities	51	17	496	291	Burlington Power & Light	N. A.	N. A.	N. A.	N. A.	X
1960	1959	Northern States Power (through Northern States Power, Wisc.)	554	170 7/	6,113	1,576	Mississippi Valley Public Service	11	3	N. A.	56	X
1962	1961	Central Illinois Public Service	237	66	3,025	1,486	Illinois Electric & Gas	N. A.	N. A.	N. A.	N. A	X
1963	1962	Wisconsin Power & Light	209	56	2,134	824	Pleasant Springs Light & Power	N. A.	N. A.	N. A.	N. A.	X
1964	1963	Wisconsin Power & Light	211	59	2,290	987	Roxbury Light & Power	N. A.	N. A.	N. A.	N. A.	X
							Stoughton Light & Fuel	N. A.	N. A.	N. A.	N. A.	X
1964	1963	Northern States Power	685	216 7/	8,247	2,364	Deichen Power (Minn.)	N. A.	N. A.	N. A.	N. A.	X
1966	1965	Commonwealth Edison	1,997	593	31,637	14,936 11/	Central Illinois Electric & Gas	99	41	1,079	197	X
1967	1966	American Electric Power	1,988	488 8/	44,625	25,249 6/ 9/	Michigan Gas & Electric	25	12 10/	265	--	
* 1968	1967	American Electric Power	2,156 12/	524 8/ 12/	50,119	26,367 6/ 9/	Columbus & So. Ohio Electric	319	84	4,356	2,066	
* 1968	1967	Illinois Power	578	177	6,414	3,185	Central Illinois Public Service	345	99	4,354	2,903	X
* 1968	1967	Commonwealth Edison	2,403	711	37,685	17,465 11/	Central Illinois Light	238	69	2,182	1,205 13/	X
* 1968	1967	Iowa Power & Light	208	68	2,069	484	Iowa-Illinois Gas & Electric	211	80	2,093	395	X
* 1969	1967	Cincinnati Gas & Electric	741	209 15/	7,447	3,159	Cleveland Electric Illuminating	529	189 14/	11,254	4,726 11/	
							Duquesne Light	550	133	8,629	4,059	
							Dayton Power & Light	362	143	5,262	1,779 11/	
							Ohio Edison	812	232	14,210	5,106	
							Toledo Edison	335	70	4,158	1,415	
* 1969	1967	Arkansas-Missouri Power	42	16	586	--	Middle South Utilities	1,365	331	21,520	--	

UTILITY MERGERS AND ACQUISITIONS AFFECTING COMPANIES
OPERATING IN THE MIDWEST STATES, 1955-1969 --
EFFECTED OR CURRENTLY PENDING

A. MERGERS & ACQUISITIONS INVOLVING PRIVATELY-OWNED COMPANIES ONLY
(CONTINUED)

ø Coverage includes bituminous, sub-bituminous and lignite, as in Bureau of Mines statistics.

* Pending.
** Less than $500,000.

N.A.: Not available.
--: No consumption.

1/ Data from Federal Power Commission, Statistics of Privately Owned Electric Utilities in the United States (Column 9, 10 and 11) or Steam-Electric Plant Construction Cost and Annual Production Expenses (Column 7).
2/ 1955 coal consumption. 1954 figure not available.
3/ Listed in source as "Total Assets and Other Debits."
4/ Listed in source as "Total Electric Operating Revenue."
5/ Consumption of Interstate Power Co. (Iowa) only.
6/ Includes 1/2 of coal consumption of Beech Bottom Power Co., owned 50% by Ohio Power Co. and 50% by a non-affiliated utility company. Also includes coal consumed by Ohio Valley Electric Corp., owned 37.8% by American Electric Power and OVEC's wholly-owned subsidiary Indiana & Kentucky Electric Corp. (All coal purchasing for OVEC is handled by AEP.)
7/ Listed in source as "Total Gross Earnings."
8/ Listed in source as "Operating Revenues (Electric)."
9/ 1966 consumption includes 1/3 of coal consumed at Kammer Plant, owned 1/3 by Ohio Power Co. of American Electric Power. 1967 consumption includes all coal consumed at Kammer Plant, reflecting Ohio Power's total ownership of plant as of January 1, 1967.
10/ Listed in source as "Gross Revenues."
11/ Includes equivalent for relatively small quantities of other fuels.
12/ Excludes Michigan Gas & Electric Co. Accounts not consolidated pending sale of gas properties of Michigan Gas & Electric.
13/ Includes 49,538 tons consumed for production of process steam.
14/ Includes revenue billed as of December 31, 1967, only.
15/ Listed in source as "Total Revenue."

Source: (Col. 1, 3-6, 8-11): Moody's Investors Service, Moody's Public Utility Manual, 1955-1968 (New York: Moody's Investors Service, 1955-1968), unless otherwise noted.

UTILITY MERGERS AND ACQUISITIONS AFFECTING COMPANIES OPERATING IN THE MIDWEST STATES, 1955-1969 -- EFFECTED OR CURRENTLY PENDING

A. MERGERS & ACQUISITIONS INVOLVING PRIVATELY-OWNED COMPANIES ONLY (CONTINUED)

Source: (Col. 7 and 12): 1954-1957: Carl J. Coash (Publisher), Keystone Coal Buyers Manual, 1957-1960 (New York: McGraw-Hill Publishing Co., 1957-1960), unless otherwise noted.

1959-1967: National Coal Association, Steam-Electric Plant Factors, 1959-1968 Editions (Washington, D. C.: National Coal Association, 1960-1968).

UTILITY MERGERS AND ACQUISITIONS AFFECTING COMPANIES OPERATING IN THE MIDWEST STATES, 1955-1969 -- EFFECTED OR CURRENTLY PENDING

B. ACQUISITIONS OF MUNICIPAL ELECTRIC SYSTEMS

Year Acquisition	Data	ACQUIRING UTILITY Name	Total Assets	Gross Operating Revenues	Sales	Coal * Consumption	MUNICIPAL SYSTEM Name	Total Assets	Gross Operating Revenues	Sales	Coal * Consumption
			----($ Million)----		(Million kwh)	(1,000 tons)		---($ Thousand)---		(Thousand kwh)	(1,000 tons)
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
1955	1954	Commonwealth Edison	$ 1,188	$ 310	15,597	8,013	Hinsdale, Illinois	N.A.	N.A.	N.A.	N.A.
1956	1955	Illinois Power	360	78	3,100	1,533	Salem, Illinois	N.A.	N.A.	N.A.	--
1957	1956	Cincinnati Gas & Electric	358	114	4,124	2,042	St. Bernard, Ohio	N.A.	N.A.	N.A.	N.A.
1957	1956	Northern States Power	577	139 1/	4,379	1,457	Delhi, Minnesota	N.A.	N.A.	N.A.	--
							North Redwood, Minnesota	N.A.	N.A.	N.A.	--
1957	1956	American Electric Power (through Ind. & Mich. Elec.)	1,159	268	20,721	16,138 2/	Kendallville, Indiana	N.A.	N.A.	N.A.	N.A.
1958	1957	Missouri Public Service	57	13	374	80	Burgess, Missouri	N.A.	N.A.	N.A.	--
1958	1957	American Electric Power (through Ind. & Mich. Elec.)	1,283	284	21,428	17,428 2/	Monroe, Indiana	N.A.	N.A.	N.A.	--
1959	1958	Northern Ind. Public Service	353	92 3/	2,763	702	Pierceton, Indiana	N.A.	N.A.	N.A.	--
1960	1959	American Electric Power (through Ind. & Mich. Elec.)	1,458	324	25,866	18,972 2/	Decatur, Indiana	N.A.	N.A.	N.A.	19
1960	1959	American Electric Power (through Ohio Power)	1,458	324	25,866	18,972 2/	Minerva, Ohio	N.A.	N.A.	N.A.	N.A.
1961	1960	Northern Ind. Public Service	422	124 3/	3,728	1,135	Goshen, Indiana	N.A.	N.A.	N.A.	N.A.
1961	1960	Public Service of Indiana	471	92 4/	5,134	2,776	Tipton, Indiana	N.A.	N.A.	N.A.	--
1962	1961	Illinois Power	422	116	3,987	2,063	Bloomington, Illinois	N.A.	300	N.A.	--
1962	1961	American Electric Power (through Ind. & Mich. Elec.)	1,561 5/	352 3/ 5/	28,522	20,018 2/	Portland, Indiana	N.A.	N.A.	N.A.	N.A.
1962	1961	Otter Tail Power	74	21	609	588	Wilton, Minnesota	N.A.	N.A.	N.A.	--
1962	1961	Commonwealth Edison	1,840	492	23,338	10,821	Woodstock, Illinois	N.A.	N.A.	N.A.	28
1964	1963	Public Service of Indiana	503	113 4/	6,295	3,227	Crothersville, Indiana	N.A.	N.A.	N.A.	--
1964	1963	American Electric Power (through Ohio Power)	1,724	394 6/	33,244	21,988 2/	Paulding, Ohio	N.A.	N.A.	N.A.	N.A.
1964	1963	Iowa Power & Light	172	57	1,624	323	Grimes, Iowa	N.A.	N.A.	N.A.	N.A.
1965	1964	Public Service of Indiana	514	120 4/	6,848	3,451	Connersville, Indiana	N.A.	N.A.	N.A.	--
1965	1964	American Electric Power (through Ohio Power)	1,753	419 6/	36,218	22,634 2/	Willard, Ohio	N.A.	283	11,100 7/	N.A.
1966	1965	Northern Ind. Public Service	636	191 3/	5,430	1,850	Nappanee, Indiana	N.A.	455	20,200 7/	18
1966	1965	Illinois Power	517	151	5,443	3,028	Fithian, Illinois	N.A.	N.A.	N.A.	--
							Sawyerville, Illinois	N.A.	N.A.	N.A.	--
1967	1966	Public Service of Indiana	540	136 4/	8,249	3,881	Rushville, Indiana	N.A.	N.A.	N.A.	23
1967	1966	Northern States Power	820	254 1/	10,554	3,092	Bayport, Minnesota	N.A.	N.A.	8/	--
1967	1966	Wisconsin Public Service	194	68	2,831	1,023	Kewanee, Wisconsin	N.A.	179	N.A.	--
1967	1966	Michigan Gas & Electric	25	12 9/	265	--	Constantine, Michigan	N.A.	N.A.	N.A.	N.A.
1968	1967	Northern States Power	926	271 1/	11,564	2,691	Mazeppa, Minnesota	N.A.	53	50 7/	N.A.
1968	1967	Public Service of Indiana	551	144 4/	8,821	3,892	Vevay, Indiana	N.A.	N.A.	N.A.	--
1968	1967	Illinois Power	578	177	6,414	3,185	Ogden, Illinois	N.A.	N.A.	N.A.	--

UTILITY MERGERS AND ACQUISITIONS AFFECTING COMPANIES OPERATING IN THE MIDWEST STATES, 1955-1969 -- EFFECTED OR CURRENTLY PENDING

B. ACQUISITIONS OF MUNICIPAL ELECTRIC SYSTEMS (CONTINUED)

* Coverage includes bituminous, sub-bituminous and lignite, as in Bureau of Mines statistics.

N. A. : Not available.
-- No consumption.

1/ Listed in source as "Total Gross Earnings."
2/ Includes 1/2 of coal consumption of Beech Bottom Power Co., owned 50% by Ohio Power Co. and 50% by a non-affiliated utility company. Also includes coal consumption of Ohio Valley Electric Corp. and OVEC's wholly-owned subsidiary, Indiana & Kentucky Electric Corp. (all coal purchasing for OVEC is handled by AEP). From 1959 on, includes 1/3 of coal consumed at the Kammer Plant, owned 1/3 by Ohio Power Co. and 2/3 by a non-affiliated utility company.
3/ Listed in source as "Operating Revenues."
4/ Listed in source as "Total Operating Revenue (All Electric)."
5/ Based on "Uniform System of Accounts" effective January 1, 1961. Data for 1960 and earlier years not strictly comparable.
6/ Listed in source as "Operating Revenues (Electric)."
7/ Total annual generation. Kwh sales figure not available.
8/ No generation.
9/ Listed in source as "Gross Revenues."

Source: (Cols. 1-6 and 8): Moody's Investors Service, Moody's Public Utility Manual, 1955-1968 (New York: Moody's Investors Service, 1955-1968).

(Col. 7) 1954: Federal Power Commission, Steam-Electric Plant Construction Cost and Annual Production Expenses, 1954 Supplement.

1955-1958: Carl J. Coash (Publisher), Keystone Coal Buyers Manual (New York: McGraw-Hill Publishing Co., 1957-1960).

(Cols. 7 and 12): National Coal Association, Steam-Electric Plant Factors, 1959-1968 Editions (Washington, D. C.: National Coal Association, 1960-1968).

(Cols. 9-11): American Public Power Association, Public Power, January issues, 1962-1968.

TABLE XXX

RANKING TWENTY COAL* PURCHASING UTILITIES WITH GENERATING STATIONS IN THE MIDWEST STATES, 1967

(RANKED BY COAL* CONSUMPTION IN THE MIDWEST STATES)

Rank	Company and Subsidiary	Plant	Location	Initial Year of Operation	Plant Capacity	Total Company Capacity	1967 Coal* Consumption (1,000 tons) In Midwest States	In Other States	Total Consumption of Company in Midwest States (Total of Col. 8)
					------------(Mw)------------				
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Tennessee Valley Authority 2/					15,973		6,844	19,930
		Paradise	Drakesboro, Ky.	1963	1,408.0		3,807		
		Shawnee	Paducah, Ky.	1953	1,725.0		4,230		
		Gallatin	Gallatin, Tenn.	1956	1,255.2		2,477		
		Johnsonville A & B	Johnsonville, Tenn.	1951/1958	1,485.2		2,615		
		Kingston	Kingston, Tenn.	1954	1,700.0		3,088		
		John Sevier	Rogersville, Tenn.	1955	823.3		1,368		
		T.H. Allen	Memphis, Tenn.	1958	990.0		956		
		Bull Run	Oak Ridge, Tenn.	1967	950.0		1,389		
2	Commonwealth Edison Co.					9,153			17,465
		Calumet	Chicago, Ill.	1921	234.5		241		
		Crawford	Chicago, Ill.	1924/1928	701.5		1,539		
		Dixon	Dixon, Ill.	1918	119.0		169		
		Fisk	Chicago, Ill.	1903/1914	601.6		1,175		
		Joliet	Joliet, Ill.	1917	1,862.4		4,243		
		Northwest	Chicago, Ill.	1912	223.8		170		
		Powerton	Pekin, Ill.	1928	320.0		554		
		Ridgeland	Stickney, Ill.	1950	690.0		1,208		
		Waukegan	Waukegan, Ill.	1923	1,042.8		1,945		
		Will County	Lockport Twp., Ill.	1955	1,268.9		2,918		
		Fordam	Rockford, Ill.	1896	75.3		55		
		Sabrooke	Rockford, Ill.	1949	146.4		178		
		Kincaid	Kincaid, Ill.	1967	659.7		1,093		

Total Company Capacity	1967 Coal* Consumption (1,000 tons)				Consumption (Col. 10) as % of Total Utility Consumption in Midwest States 1/
	In Midwest States	In Other States	Total Consumption of Company in Midwest States	Total Company Consumption	
Mw)------------			(Total of Col. 8)	(9) + (10)	
(7)	(8)	(9)	(10)	(11)	(12)
15,973		6,844	19,930	26,774 3/	21.22%
	3,807				
	4,230				
	2,477				
	2,615				
	3,088				
	1,368				
	956				
	1,389				
9,153			17,465	17,465 3/	18.59
	241				
	1,539				
	169				
	1,175				
	4,243				
	170				
	554				
	1,208				
	1,945				
	2,918				
	55				
	178				
	1,093				

RANKING TWENTY COAL* PURCHASING UTILITIES WITH GENERATING STATIONS
IN THE MIDWEST STATES, 1967
(RANKED BY COAL* CONSUMPTION IN THE MIDWEST STATES) (CONTINUED)

Rank	Company and Subsidiary	Plant	Location	Initial Year of Operation	Plant Capacity	Total Company Capacity	1967 Coal* Consumption (1,000 tons): In Midwest States	In Other States	Total Consumption of Company in Midwest States (Total of Col. 8)
					----------(Mw)----------				
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
	Commonwealth Edison Co. of Indiana, Inc.	State Line	Hammond, Ind.	1929	972.0		1,977		
3	American Electric Power Co.					9,307		17,828 4/	8,539
	Indiana & Michigan Electric Co.	Breed	Sullivan, Ind.	1960	450.0		1,079		
		Tanners Creek	Lawrenceburg, Ind.	1951	1,098.0		2,280		
		Twin Branch	Mishawaka, Ind.	1925	394.0		649		
	Kentucky Power Co.	Big Sandy	Louisa, Ky.	1963	265.0		778		
	Ohio Valley Electric Corp. 5/					2,390		2,728 6/	3,753 6/
	Indiana-Kentucky Electric Corp.	Clifty Creek	Madison, Ind.	1955	1,303.6		3,753		
4	Union Electric Co.					3,118		-	4,303
		Cahokia	Monsanto, Ill.	1923	300.0		233		
		Venice #2	Venice, Ill.	1942	500.0		1,028		
		Ashley	St. Louis, Mo.	1904	70.0		71		
		Meramec	St. Louis, Mo.	1953	923.0		2,411		
		Sioux	W. Alton, Mo.	1967	549.8		466		
	Missouri Power & Light Co.	Kirksville 7/	Kirksville, Mo.	-/1943 8/	5.0		18		
		Mexico 7/	Mexico, Mo.	-/1950 8/	19.0		76		

otal Company Capacity	1967 Coal* Consumption (1,000 tons)				Consumption (Col. 10) as % of Total Utility Consumption in Midwest States 1/
)------------	In Midwest States	In Other States	Total Consumption of Company in Midwest States (Total of Col. 8)	Total Company Consumption (9) + (10)	
(7)	(8)	(9)	(10)	(11)	(12)
	1,977				
		17,828 4/	8,539	26,367	9.09%
9,307					
	1,079				
	2,280				
	649				
	778				
		2,728 6/	3,753 6/	6,481 6/	4.00 6/
2,390					
	3,753				
		-	4,303	4,303	4.58
3,118					
	233				
	1,028				
	71				
	2,411				
	466				
	18				
	76				

RANKING TWENTY COAL[a] PURCHASING UTILITIES WITH GENERATING STATIONS
IN THE MIDWEST STATES, 1967
(RANKED BY COAL[a] CONSUMPTION IN THE MIDWEST STATES) (CONTINUED)

							1967 Coal[a] Consumption (1,000 tons)		
Rank	Company and Subsidiary	Plant	Location	Initial Year of Operation	Plant Capacity	Total Company Capacity	In Midwest States	In Other States	Total Consumption of Company in Midwest States
					------------(Mw)------------				(Total of Col. 8)
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
5	Wisconsin Electric Power Co.					2,567		-	4,207
		Commerce St.	Milwaukee, Wisc.	1903	67.5		6		
		East Wells St. 7/	Milwaukee, Wisc.	N. A.	13.7		33		
		Lakeside	St. Francis, Wisc.	1920	310.8		327		
		N. Oak Creek	Oak Creek, Wisc.	1953	500.0		1,226		
		Port Washington	Port Washington, Wisc.	1935	400.0		782		
		S. Oak Creek	Oak Creek, Wisc.	1959	1,170.0		1,831		
	Wisconsin Michigan Power Co.	Appleton 7/	Appleton, Wisc.	N. A.	15.0		2		
6	Public Service Co. of Indiana					1,664		-	3,892
		Dresser	Terre Haute, Ind.	1924	221.0		240		
		Edwardsport	Edwardsport, Ind.	1918/1944	133.0		341		
		Gallagher	New Albany, Ind.	1958	600.0		1,748		
		Noblesville	Noblesville, Ind.	1950	100.0		65		
		Wabash River	Terre Haute, Ind.	1953	521.0		1,498		
7	Electric Energy, Inc.					1,100		-	3,548
		Joppa	Joppa, Ill.	1953	1,100.3		3,548		
8	Illinois Power Co.					1,394		-	3,185
		Havana	Havana, Ill.	1947	230.0		366		
		Hennepin	Hennepin, Ill.	1953	306.3		654		
		Vermilion	Oakwood, Ill.	1955	182.3		483		
		Wood River	Wood River, Ill.	1949	650.1		1,682		

Total Company Capacity	1967 Coal* Consumption (1,000 tons)				Consumption (Col. 10) as % of Total Utility Consumption in Midwest States 1/
	In Midwest States	In Other States	Total Consumption of Company in Midwest States	Total Company Consumption	
v)------------			(Total of Col. 8)	(9) + (10)	
(7)	(8)	(9)	(10)	(11)	(12)
2,567		-	4,207	4,207	4.48%
	6				
	33				
	327				
	1,226				
	782				
	1,831				
	2				
1,664		-	3,892	3,892	4.14
	240				
	341				
	1,748				
	65				
	1,498				
1,100		-	3,548	3,548 3/	3.78
	3,548				
1,394		-	3,185	3,185	3.39
	366				
	654				
	483				
	1,682				

RANKING TWENTY COAL* PURCHASING UTILITIES WITH GENERATING STATIONS
IN THE MIDWEST STATES, 1967
(RANKED BY COAL* CONSUMPTION IN THE MIDWEST STATES) (CONTINUED)

Rank	Company and Subsidiary	Plant	Location	Initial Year of Operation	Plant Capacity	Total Company Capacity	1967 Coal* Consumption (1,000 tons): In Midwest States	In Other States	Total Consumption of Company in Midwest States (Total of Col. 8)
					-----(Mw)-----				
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
9	Central Illinois Public Service Co.					1,072		-	2,903
		Coffeen	Montgomery Co., Ill.	1965	330.0		1,066		
		Grand Tower	Grand Tower, Ill.	1922	216.0		499		
		Hutsonville	Hutsonville, Ill.	1940	200.0		513		
		Meredosia	Meredosia, Ill.	1948	325.0		825		
10	Northern States Power Co. (Minn.)					2,217		254	2,437
		Black Dog	Minneapolis, Minn.	1952	486.7		754		
		High Bridge	St. Paul, Minn.	1924	463.8		642		
		Minnesota Valley	Granite Falls, Minn.	1930	66.0		59		
		Red Wing 7/	Red Wing, Minn.	N. A.	23.0		28		
		Riverside	Minneapolis, Minn.	1911/1916	518.4		795		
		Southeast	Minneapolis, Minn.	N. A.	30.0		18		
		Island 7/	St. Paul, Minn.	N. A.	20.0		15		
		Whitney 7/	St. Cloud, Minn.	1940	20.0		12		
		Wilmarth	Mankato, Minn.	1948	25.0		23		
		Winona	Winona, Minn.	1917	26.0		34		
	Northern States Power Co. (Wisc.)	Edison 7/	La Crosse, Wisc.	N. A.	6.5		1		
		French Island	La Crosse, Wisc.	1940	25.0		56		

otal Company Capacity	1967 Coal * Consumption (1,000 tons)				Consumption (Col. 10) as % of Total Utility Consumption in Midwest States 1/
	In Midwest States	In Other States	Total Consumption of Company in Midwest States	Total Company Consumption	
)-----------			(Total of Col. 8)	(9) + (10)	
(7)	(8)	(9)	(10)	(11)	(12)
1,072		-	2,903	2,903	3.09%
	1,066				
	499				
	513				
	825				
2,217		254	2,437	2,691	2.59
	754				
	642				
	59				
	28				
	795				
	18				
	15				
	12				
	23				
	34				
	1				
	56				

RANKING TWENTY COAL* PURCHASING UTILITIES WITH GENERATING STATIONS
IN THE MIDWEST STATES, 1967
(RANKED BY COAL* CONSUMPTION IN THE MIDWEST STATES) (CONTINUED)

							1967 Coal* Consumption (1,000 tons)		
Rank	Company and Subsidiary	Plant	Location	Initial Year of Operation	Plant Capacity	Total Company Capacity	In Midwest States	In Other States	Total Consumption of Company in Midwest States
					(Mw)				(Total of Col. 8)
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
11	Indianapolis Power & Light Co.					1,101		-	2,159
		E. W. Stout	Indianapolis, Ind.	1931	383.8		821		
		Perry K & W	Indianapolis, Ind.	N. A.	59.1		51		
		H. T. Prichard	Centerton, Ind.	1949	396.4		869		
		Petersburg	Petersburg, Ind.	1967	261.7		418		
12	Kansas City Power & Light Co.					1,209		-	1,989
		Grand Ave.	Kansas City, Mo.	1903	126.8		38		
		Hawthorn	Kansas City, Mo.	1951	363.0		160		
		Montrose	Montrose, Mo.	1958	563.1		1,791		
13	Northern Indiana Public Service Co.					871	446	-	1,969
		Bailly	Dune Acres, Ind.	1962	194.0		289		
		Michigan City	Michigan City, Ind.	1930	215.0		1,213		
		D.H. Mitchell	Gary, Ind.	1956	414.3		21		
		Nappanee 7/	Nappanee, Ind.	N. A.	12.3				
14	Louisville Gas & Electric Co.					1,253	1,686	-	1,929
		Cane Run	Louisville, Ky.	1954	744.7		243		
		Paddy's Run	Louisville, Ky.	1942	337.5				

Total Company Capacity	1967 Coal Consumption (1,000 tons)				
Total Company Capacity	In Midwest States	In Other States	Total Consumption of Company in Midwest States	Total Company Consumption	Consumption (Col. 10) as % of Total Utility Consumption in Midwest States 1/
w)-----------			(Total of Col. 8)	(9) + (10)	
(7)	(8)	(9)	(10)	(11)	(12)
1,101		-	2,159	2,159	2.30%
	821				
	51				
	869				
	418				
1,209		-	1,989	1,989	2.12
	38				
	160				
	1,791				
		-	1,969	1,969	2.10
871	446				
	289				
	1,213				
	21				
		-	1,929	1,929	2.05
1,253	1,686				
	243				

RANKING TWENTY COAL* PURCHASING UTILITIES WITH GENERATING STATIONS
IN THE MIDWEST STATES, 1967
(RANKED BY COAL* CONSUMPTION IN THE MIDWEST STATES) (CONTINUED)

							1967 Coal* Consumption (1,000 tons)		
Rank	Company and Subsidiary	Plant	Location	Initial Year of Operation	Plant Capacity	Total Company Capacity	In Midwest States	In Other States	Total Consumption of Company in Midwest States
					------------(Mw)------------				(Total of Col. 8)
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
15	Wisconsin Power & Light Co.					643		-	1,340
		Blackhawk	Beloit, Wisc.	1917/1949	57.5		50		
		Edgewater	Sheboygan, Wisc.	1931	129.0		250		
		Nelson Dewey	Cassville, Wisc.	1959	227.3		626		
		Rock River	Beloit, Wisc.	1954	159.4		414		
16	Central Illinois Light Co.					523		-	1,205
		E. D. Edwards	Bartonville, Ill.	1960	125.0		418		
		Liberty St.	Peoria, Ill.	1917	25.0		59 9/		
		R. S. Wallace	E. Peoria, Ill.	1925	301.4		728		
17	Kentucky Utilities Co.					762		-	1,108
		E. W. Brown	Bergin, Ky.	1957	293.2		498		
		Green River	Carrollton, Ky.	1950	263.6		530		
		Pineville	Pineville, Ky.	1923	37.5		30		
		Tyrone	Tyrone, Ky.	1947	137.5		50		
18	Wisconsin Public Service Corp.					607		-	1,058
		Weston	Green Bay, Wisc.	1954	135.0		130		
		Pulliam	Rothchild, Wisc.	1927	392.5		928		
19	Minnesota Power & Light Co.					520		-	949
		Aurora	Aurora, Minn.	1953	116.1		319		
		Clay Boswell	Cohasset, Minn.	1958	150.0		427		
		M. L. Hibbard	Duluth, Minn.	1931	122.5		178		

Total Company Capacity	1967 Coal* Consumption (1,000 tons) In Midwest States	In Other States	Total Consumption of Company in Midwest States	Total Company Consumption	Consumption (Col. 10) as % of Total Utility Consumption in Midwest States 1/
w)------------			(Total of Col. 8)	(9) + (10)	
(7)	(8)	(9)	(10)	(11)	(12)
643		-	1,340	1,340	1.43%
	50				
	250				
	626				
	414				
523		-	1,205	1,205	1.28
	418				
	59 9/				
	728				
762		-	1,108	1,108	1.18
	498				
	530				
	30				
	50				
607		-	1,058	1,058	1.13
	130				
	928				
520		-	949	949	1.01
	319				
	427				
	178				

RANKING TWENTY COAL* PURCHASING UTILITIES WITH GENERATING STATIONS
IN THE MIDWEST STATES, 1967
(RANKED BY COAL* CONSUMPTION IN THE MIDWEST STATES) (CONTINUED)

Rank	Company and Subsidiary	Plant	Location	Initial Year of Operation	Plant Capacity	Total Company Capacity	1967 Coal* Consumption (1,000 tons): In Midwest States	In Other States	Total Consumption of Company in Midwest States
					------------(Mw)------------				(Total of Col. 8)
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
19	Minnesota Power & Light Co. (Continued)								
	Superior Water, Light & Power Co.	Winslow	Superior, Wisc.	1894/1942	25.2		25		
20	Dairyland Power Coop.					263			
		Alma	Alma, Wisc.	1947	187.8		610	-	746
		Genoa 7/	Genoa, Wisc.	N.A.	14.0		4		
		Stoneman	Cassville, Wisc.	1950	51.8		132		
TOTAL					41,457.4	55,317		24,926	84,861

* Coverage includes bituminous, sub-bituminous, and lignite, as in Bureau of Mines statistics.
N. A.: Not Available.

1/ 93,929,000 tons (includes 49,538 tons consumed for production of process steam).
2/ Data for fiscal year ended June 30, 1967.
3/ Includes equivalent for relatively small quantities of other fuels.
4/ Includes 1/2 of total coal consumed (648,000 tons) by Beach Bottom Power Co., owned 50% by Ohio Power Co. of American Electric Power and 50% by a non-affiliated utility company.
5/ Owned 37.8% by American Electric Power. All coal purchasing for OVEC is handled by AEP.

Total Company Capacity (Mw)	1967 Coal* Consumption (1,000 tons): In Midwest States	In Other States	Total Consumption of Company in Midwest States (Total of Col. 8)	Total Company Consumption (9) + (10)	Consumption (Col. 10) as % of Total Utility Consumption in Midwest States 1/
(7)	(8)	(9)	(10)	(11)	(12)
	25				
263		-	746	746	0.79
	610				
	4				
	132	--			
55,317		24,926	84,861	109,787	90.34%

ectric Power and

RANKING TWENTY COAL* PURCHASING UTILITIES WITH GENERATING STATIONS
IN THE MIDWEST STATES, 1967
(RANKED BY COAL* CONSUMPTION IN THE MIDWEST STATES) (CONTINUED)

6/ Included in total for American Electric Power.
7/ Classified by Federal Power Commission as a "small plant" (less than 25,000 kw of installed capacity. Consumption data were estimated by source on the basis of available generating statistics.
8/ Year shown refers to year of completion of last unit added. Initial year of plant operation not available.
9/ Includes 49,538 tons consumed for production of process steam.

Source: (Col. 1-4, 6 and 8-10): National Coal Association, Steam-Electric Plant Factors, 1968 Edition (Washington, D.C.: National Coal Association, 1968), Table 1 and Table 2.

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TABLE XXXI

SELECTED STATISTICS 1/ ON THE TWENTY LARGEST UTILITY COMPANIES IN THE MIDWEST STATES (RANKED BY 1967 COAL CONSUMPTION)

Rank	Company	Coal Consumption in the Midwest States	Total Generating Capacity	Total Assets	Gross Operating Revenues
		(1,000 tons)	(Mw)	------($ Million)	------
(1)	(2)	(3)	(4)	(5)	(6)
1	Tennessee Valley Authority 2/	19,930	15,973	$ 2,917	$ 351
2	Commonwealth Edison Co.	17,465	9,153	2,403	711
3	American Electric Power Co.	8,539 3/	9,307	2,156 4/	524 4/ 5/
4	Union Electric Co.	4,303	3,118	1,022	240
5	Wisconsin Electric Power Co.	4,207	2,567	705	213
6	Public Service Co. of Indiana	3,892	1,664	551	144 6/
7	Electric Energy, Inc.	3,548	1,100	117	32
8	Illinois Power Co.	3,185	1,394	578	177
9	Central Illinois Public Service Co.	2,903	1,072	345	99
10	Northern States Power Co.	2,437	2,217	926	271 7/
11	Indianapolis Power & Light Co.	2,159	1,101	288	81
12	Kansas City Power & Light Co.	1,989	1,209	366	95
13	Northern Indiana Public Service Co.	1,969	871	760	226
14	Louisville Gas & Electric Co.	1,929	1,253	279	98
15	Wisconsin Power & Light Co.	1,340	643	232	77
16	Central Illinois Light Co.	1,205 8/	523	238	69
17	Kentucky Utilities Co.	1,108	762	218	65
18	Wisconsin Public Service Corp.	1,058	607	211	74
19	Minnesota Power & Light Co.	949	520	147	44
20	Dairyland Power Cooperative	746	263	116	15
TOTAL		84,861	55,317	$14,575	$3,606

SELECTED STATISTICS 1/ ON THE TWENTY LARGEST UTILITY COMPANIES IN THE MIDWEST STATES (RANKED BY 1967 COAL* CONSUMPTION) (CONTINUED)

* Coverage includes bituminous, sub-bituminous and lignite, as in Bureau of Mines statistics.

1/ Data includes all subsidiaries on a consolidated basis, except where otherwise noted.
2/ Data for fiscal year ended June 30, 1967.
3/ Includes 3,753,000 tons consumed by Indiana-Kentucky Electric Corp., a subsidiary of Ohio Valley Electric Corp. (owned 37.8% by AEP). All coal purchasing for OVEC is handled by AEP.
4/ Excludes Michigan Gas and Electric Co. Accounts for 1967 not consolidated pending sale of gas properties of Michigan Gas & Electric.
5/ Listed in source as "Operating Revenues (Electric)."
6/ Listed in source as "Total Operating Revenues (All Electric)."
7/ Listed in source as "Total Gross Earnings."
8/ Includes 49,538 tons consumed for production of process steam.

Source: (Cols.1 & 3): National Coal Association, Steam-Electric Plant Factors, 1968 Edition (Washington, D.C.: National Coal Association, 1968), Table 1.

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TABLE XXXII

ELECTRIC UTILITY COAL* CONSUMPTION IN THE MIDWEST STATES, 1967

State	1967 Utility Coal* Consumption (1,000 tons)
(1)	(2)
Illinois	28,295 1/
Iowa	3,025 2/
Indiana	19,120
Kentucky	12,990
Minnesota	4,244
Missouri	6,463
Tennessee	11,893
Wisconsin	7,899
TOTAL	93,929

* Coverage includes bituminous, sub-bituminous and lignite, as in Bureau of Mines statistics.

1/ Includes 49,538 tons consumed for production of process steam.

2/ Includes 75,700 tons consumed for purposes other than electrical generation.

Source: National Coal Association, Steam-Electric Plant Factors, 1968 Edition (Washington, D.C.: National Coal Association, 1968), Table 1.

VITA AND BIBLIOGRAPHY

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Director, Washington Office
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Education		B. A. (Geology), Cornell University, 1941 Ph. D. (Economics), Cornell University, 1949
Experience	1949-50	- Asst. Prof., University of Minnesota at Duluth
	1951	- Commodity-Industry Analyst, U.S. Bureau of Mines
	1951-52	- Staff member, President's Materials Policy Commission (prepared supply forecasts to 1975 for copper, lead, zinc, tin and rubber)
	1953-54	- Consultant, Materials Area, National Security Resources Board and successor agency, Office of Defense Mobilization (assisted in formulation of stockpile and mineral industry mobilization policy)
	1954-55	- Central Intelligence Agency (Branch Chief, nonferrous metals and nonmetallic minerals)
	1955-61	- Senior Research Associate, Resources for the Future, Inc. (conducted research on the future supply of fuels and energy sources, including nuclear energy and solar energy, and the future supply of the major metals)
	1961-	- Director, Washington Office, National Economic Research Associates, Inc. (conduct and supervise research on a wide variety of subjects, with emphasis on national, regional and local supply-demand position of fuels and energy resources for various future periods; testify as expert witness on these subjects before state and federal courts, regulatory agencies and Congressional and Departmental hearings)
Professional Associations		Member, American Economic Association and American Institute of Mining, Metallurgical and Petroleum Engineers (former Chairman, Council of Mineral Economics in latter organization); Fellow, Geological Society of America; Fellow, Institute of Petroleum
Honorary Associations and Awards		Phi Beta Kappa; Phi Kappa Phi; 1961 Recognition Award, Texas Independent Producers and Royalty Owners' Association, for contribution to Energy in the American Economy (see bibliography)

Other Professional Activities

Frequent speaker and lecturer at professional and trade association meetings and at seminars and symposia at various universities and colleges.

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DEFENDANT'S EXHIBIT 86

Report

STRUCTURE AND GEOGRAPHY OF THE ELECTRIC UTILITY MARKET FOR COAL

by: Abraham Gerber

STRUCTURE AND GEOGRAPHY OF THE ELECTRIC UTILITY MARKET FOR COAL

A. Coal is often mistakenly thought of by the layman as a homogeneous fungible product. In fact, coal is a product with a wide range of diversity in its chemical and physical properties which must be thoroughly understood and carefully evaluated by those who buy and use coal.

Coals vary widely in their sulfur content, ash content, volatility, fusion temperature, grindability and Btu content, all of which are significant in determining whether a given coal is technically and/or economically usable in modern sophisticated electric utility boilers.

Although coal with any given set of physical and chemical characteristics can be burned in a boiler designed to do so, once a boiler is constructed, it is limited within a fairly narrow range to the use of the coal with those properties for which it has been designed. Apart from the physical limitation on the ability to burn coals that differ in their chemical and physical characteristics from the coal for which the boiler was originally designed, substantial departures from those characteristics can also have significant economic effects. For example, a lower BTU content could require the transportation of larger tonnages than was originally anticipated and a higher ash content could materially increase the cost of ash handling and/or boiler maintenance.

By far the largest market for coal both present and future in the states of the Midwest and nationally is the electric power generation market. This market also represents the only significant growth market for coal. It also exemplifies most clearly the factors that must be considered in arranging for coal supply.

B. Because of the need to assure a supply of coal that satisfies the physical and chemical requirements of the equipment designed, the complexities of administering multiple coal contracts and the development of large-scale transportation arrangements with their attendant economies, coal supply for large power plants is likely to be developed with few (two or three) producers. Indeed, many plants are supplied by only a single producer from a single mine opened specifically to serve that single facility.

In considering whether a particular coal mine can compete for the business of a power plant, several factors must be weighed. These include the cost of coal at the mine (this could vary widely for a number of reasons most important of which is the difference between deep and strip mining costs), the location of the mine relative to the consumer and the transportation costs involved, the Btu content of the coal and the suitability of the physical and chemical properties of the coal produced by a given mine for the power plant facility.

1. The Trend Toward Long-Term Contracts

In recent years, there has been a growing trend toward long-term contractual commitments to meet the coal requirements of a particular electric power generating plant. The increasing size of electric power generating units and plants has been accompanied by an increase in the quantity of coal required. A modern large coal-fired generating unit of a thousand Megawatts capacity may cost as much as 150 to 200 million dollars. This major investment can be jeopardized by a disruption in the supply of coal. Utilities are, therefore, concerned with assuring the supply of coal to such a plant over its life. A unit of this size would require approximately 2-1/2 million tons of coal annually or about 75 million tons of coal over its 30-year life. A plant containing three such units (a size likely to become increasingly commonplace) would, therefore require a total of committed minable reserves of well over 200 million tons. Furthermore prior to determining the type of fuel and the plant location, the utility makes every effort to arrive at a reasonably firm estimate of fuel costs for the life of the plant. Once the plant decision is made as to fuel and location, the utility will firm up the fuel cost estimates with long-term contractual commitments.

Prior to construction of the power plant, therefore, the utility will typically arrange long-term contracts for all or at least a major portion of the total fuel requirements of the plant. In doing so, it will not only seek the lowest possible price per Btu of delivered coal, it

will also seek assurance of the coal supplier's capability of providing the required quantities of coal over a long period of time. Utilities are, therefore, concerned about the reliability of the coal supplier and his past record of performance in satisfying contractual commitments. It will weigh heavily its previous experience with potential suppliers and will carefully investigate the availability of adequate reserves within the supplier's control to satisfy the contractual commitments. The utility will seek independent geological verification of the existence and size of the coal reserve and the physical and chemical properties of the coal. These are given careful review since the coal-burning equipment will be designed to handle the type of coal that is to be made available. The coal supply is arranged for prior to the construction of a plant and the location and design of a plant are frequently determined by the coal supply arrangements that can be made.

The long-term contractual commitments are not only desirable from the consumer's standpoint, but are also necessary from the viewpoint of the coal supplier. Such commitments generally require the development of new mining capacity. As a rule of thumb, a mine capable of producing a million tons of coal requires an investment of between six to ten million dollars. Coal producers have been reluctant to invest in new mining capacity in the absence of long-term contractual commitments for the major portion of the mine's capacity. Furthermore, obtaining

financial resources to develop new capacity often requires long-term contractual commitments.

In the electric utility market competition is not continuous in the sense that competitors may seek to serve this business on a daily, monthly or even annual basis. Rather, competition tends to be a one time thing. While competition may exist initially to supply the coal requirements of a particular electric generating plant, once the initial coal purchase is made, competition to satisfy the coal requirements of the plant is precluded for an extended period of time amounting to as much as 15 years or even the full 30-year life of the plant. Prior to the awarding of the coal supply contracts, several producers could be in competition to supply the coal requirements but once the coal contracts are awarded, competition is foreclosed.

2. Mine-Mouth Plants

When the electric generating plant is located in close proximity to the coal supply (such plants are often referred to as mine-mouth plants), assurance of the availability of an adequate coal reserve in the adjacent mining property to meet the lifetime requirements of the plant becomes even more critical. In the case of mine-mouth plants, it is often extremely difficult to arrange for an economically satisfactory alternative supply of coal should the original supplier be unable to meet the plant's requirements. In the case of a plant located so close to the mine, coal may be delivered directly from the mine to the power plant

on a conveyor belt, and the plant itself is likely to be built with no alternative coal receiving facilities. A new source of coal supply, therefore, would result in a substantial increase in cost.

3. Transportation

Where an electric generating plant is more remotely located from the source of coal, transportation costs impose limitations on competition. The cost of transportation is, in such cases a major component of the delivered cost of fuel so that differences in freight rates significantly affect the competitive position of any mine vis-a-vis a particular consuming facility. Furthermore, coal handling facilities at the consuming plant are often limited to serve only one form of transportation. For example, facilities may be provided for only barge delivery so that mines with no economic access to river transportation would be competitively foreclosed. Truck transportation is of little relevance in the case of the large modern generating units since it is only useful for relatively short distances and small tonnages. At the same time the more remote the plant from sources of coal the wider the choice among alternative suppliers under given cost conditions. Nevertheless, the availability of economic transportation and especially possibilities for single-line haul under volume or unit train arrangements, will have a major impact on the competitive alternatives. In such cases, the coal transportation costs may be affected more by rail movement patterns than by mere distance, and these differences in

transportation costs can readily outweigh the differences in mine prices. In other words, a mine may be foreclosed from competition by transportation elements beyond the coal producer's control.

While prior to the construction of electric power generating facilities, competition is broader than after plant construction and several potential suppliers may compete for the location of the power plant in an area that would make their own coal supply most advantageous, even this competition is limited by the needs of the electric power system and the power plant itself. The power plant requires large quantities of water for cooling purposes and a sufficiently large site not only for the plant itself, but also for coal storage and ash storage. In addition, the cost of transmission and system requirements with respect to voltage control and reliability must also be considered.

Thus, competition among mines for the location of a given power plant is limited by the combined effect of all these factors. Any determination of which mines can compete for the coal requirements of a particular facility must be based on the specific facts pertinent to that plant and the mines involved.

4. The Limited Spot Market for Coal

The trend toward long-term contractual commitments to meet the total requirements of a particular electric power generating plant has tended to eliminate, even though it has not eliminated altogether, the spot market for coal. From time to time, a utility consumer may

purchase small quantities of coal on the spot market and long-term contracts are often written to permit some flexibility for these and other purposes. However, because utilities are increasingly arranging for bulk transportation of coal supply on a long-term basis, the opportunities for spot purchases are declining except in those few cases in which small mines may be located in such proximity to make them capable of providing some relatively small deliveries at low cost.

The cost advantages of train-load deliveries compared with rail rates for car-load deliveries are such as to limit the desirability of such spot purchases. Furthermore, the growing practice of the coal producers of expanding mine capacity only to meet the long-term contractual commitments, and the gradual disappearance of the very small truck mines has tended to limit the production capacity available for spot sales.

C. Current production figures do not provide an adequate measure of a coal producer's market power. Because a major market for coal is the electric power generating market and long-term supply assurance is required, the critical determinant of whether a coal company is capable of offering effective competition as a coal supplier is the level of uncommitted coal reserves under its control. Current production reflects past commitments of coal reserves and these cannot be sold a second time. Additional sales for substantial quantities cannot be made without the existence of a verifiable uncommitted reserve within the coal producer's control.

In view of the factors noted above, as well as the respective reserve positions of United Electric and Freeman, the degree of potential competition that did or could have existed in the past between the two companies was within narrowly circumscribed limits. As to the future, United Electric's ability to compete with Freeman, or indeed, any other Midwestern coal producer, is severely impaired, if not totally vitiated, by its lack of uncommitted reserves.

The resources of United Electric Coal Company that are presently uncommitted to long-term contracts are smaller than the quantities necessary to satisfy the requirements of a major new electric generating unit. Unless continuity of supply can in some way be assured by the reserves available to Freeman Coal, the small uncommitted reserves of United Electric Coal Company would not be considered as a significant source of supply for a large electric generating unit.

AVERAGE SIZE OF STEAM-ELECTRIC GENERATING PLANTS AND NEW UNITS 1/ UNITED STATES 1938, 1947 AND 1951-1966

Year	Average Size: New Units	Average Size: Plants in Use
	--------(Megawatts)--------	
	(1)	(2)
1938	33	102
1947	39	118
1951	60	131
1952	66	139
1953	68	144
1954	86	154
1955	105	167
1956	119	176
1957	98	185
1958	110	197
1959	153	213
1960	158	230
1961	190	252
1962	201	281
1963	221	291
1964	220	311
1965	283	331
1966 2/	325	355

1/ As selected by the Federal Power Commission for inclusion in the annual statistical summaries (which did not include Rural Electric Cooperatives prior to 1966). In 1965, the number of plants (501) included in the summary accounted for 88 per cent of the contiguous U.S. electric utility industry's installed conventional steam-electric generating capacity of 188,213 Megawatts and for 93 per cent of the total net generation; figures for 1966 cannot be similarly compared because the effect of inclusion of the Cooperatives cannot be accurately measured in previous years.

2/ Excluding Rural Electric Cooperatives reported for the first time in 1966, when they accounted for 25 plants of 83-Megawatt average size and ten new units of 106-Megawatt average size.

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AVERAGE SIZE OF STEAM-ELECTRIC GENERATING PLANTS AND NEW UNITS 1/ UNITED STATES 1938, 1947 AND 1951-1966 (CONTINUED)

Source: Federal Power Commission, Steam-Electric Plant Construction Cost and Annual Production Expenses, various years.

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ABRAHAM GERBER

Abraham Gerber was born in New York in 1925. He received his bachelor of arts degree from Columbia College in 1948 and a master's degree from Columbia University in 1950, after which he attended the New School for Social Research for a year on a graduate scholarship.

In 1951 Mr. Gerber joined the Department of Commerce Office of Business Economics in the Input-Output Section. Shortly thereafter he joined the Bureau of Mines of the Department of the Interior, where he headed the Energy Section in the Input-Output Group of the Office of the Chief Economist.

In 1953 Mr. Gerber joined the American Electric Power Service Corporation and was appointed Administrative Assistant to the President of American Electric Power Company.

In 1961 he was appointed Secretary of the newly established System Development Committee, a committee of the Board of Directors charged with the responsibility for exploring new areas in the technical and economic development of the AEP System in all phases of its activities including such technical developments as magnetohydrodynamics research programs, nuclear power, extra-high-voltage transmission, fuel resource development, and electric transportation. He continued to do research in fuel and energy with particular emphasis on the economics

of nuclear power and the competitive relationship between nuclear power and fossil fuels as sources of electric energy generation. He also continued to provide economic projections and load forecasts for planning electric power facilities on the American Electric Power System and to provide the President of American Electric Power Company with data and analytical material on economic matters.

Mr. Gerber served as consultant to President Eisenhower's Cabinet Committee on Energy in 1953, as Secretary of the Subcommittee on Energy and Raw Materials Resources of the Engineers Joint Council Engineering Research Committee in 1961-1962, as a member of the Technical Advisory Committee of the Office of Coal Research from 1961 to the present, as a member of the Fuels Special Technical Advisory Committee of the Federal Power Commission National Power Survey in 1962-1964, and has worked closely with the Appalachian Regional Commission. He authored a technical paper and served as a reviewer of technical papers for the recent Interdepartmental Energy Study of the Federal Government.

Mr. Gerber has written numerous articles and research papers including: "The Outlook for Uranium," with John Hogerton and Leonard Geller; "The Impact of Air Pollution Control on the Economics of Energy Supply," presented at the American Power Conference in April 1965; and "Soviets Find Capital Costs Make Hydro Less Economical," with Philip Sporn for Electrical World. He recently co-authored a paper

entitled "The Social-Economic Evaluation of Water Resource Projects," presented before the International Conference on Water for Peace last May.

Mr. Gerber also has lectured before a graduate seminar on nuclear power at Massachusetts Institute of Technology.

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COAL RESERVES AND DEEP MINING

REPORT BY PAUL WEIR COMPANY

GENERAL DYNAMICS, ET AL.

vs.

UNITED STATES

Paul Weir Company
Chicago, Illinois

Job No. 1583
July, 1969

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COAL RESERVES AND DEEP MINING
REPORT BY PAUL WEIR COMPANY
GENERAL DYNAMICS, ET AL.
vs.
UNITED STATES

Analysis of Strip-Mining Potential of
Specific Coal Fields

Based on engineering data made available to us by United Electric Coal Companies, a subsidiary of General Dynamics, and on our own specialized and general knowledge of coal characteristics on the Midwestern coal fields, we have made the studies deemed necessary by us to analyze the strip-mining potential of the following coal fields, as specified by the Government in their answer to Interrogatory 44 (although not in the same order):

1. Industry Field.
2. South of the Industry Field, toward the town of Rushville, Illinois.
3. Augusta Field, located approximately ten miles west of the Industry Field.
4. Meredosia-Mount Sterling area, located in Brown County, Illinois.
5. Spring Lake Township area, Tazewell County, located directly south of the Banner Mine across the Illinois River.
6. Salt Fork Field, located near Catlin, Illinois.
7. Fidelity Mine deep coal.

Industry Field

Coal Bed Location and Occurrence

The Industry Field is located largely in the southeastern portion of Township 4 North, Range 3 West (McDonough County), with short extensions into Township 4 North, Range 2 West (McDonough County) and Township 3 North, Range 3 West (Schuyler County). At these locations the Illinois No. 2 coal bed underlies portions of a comparatively flat upland known as Gin Ridge, outcropping on both sides of Grindstone Creek, on the northern side of the ridge, and on both sides of Willow Creek, on the southern side of the ridge. The actual coal outcrop is seldom exposed, but numerous local mines have been operated near the approximate lines of outcrop, with their individual areas of depletion being unknown. A number of drill holes put down by United Electric in their exploratory program encountered "old works".

Where not partially eroded or missing, the No. 2 bed generally ranges from 24 to 30 inches in thickness. It seldom occurs in its normal thickness under less than 25 feet of cover, usually being thinned or too soft to mine where the overburden is less than 25 feet in thickness. The coal bed undulates to some extent, being either higher or lower than its expected level of occurrence within fairly broad areas of irregular shape. It has been either eroded or was never deposited in a narrow, channel-shaped strip across the center of the property, although the horizon where the coal bed should occur is well below a cover thickness of 25 feet.

Estimated Reserves

There are approximately 3,686 coal acres within the surface properties controlled by United Electric, and approximately 1,587 additional coal acres in adjoining lands not controlled by the Company, but presumably obtainable should mining operations be contemplated. With a weighted average thickness of 28.26 inches within the United Electric properties and of 27.68 inches within the adjoining properties, the total reserves of raw coal in place before mining would be 15,625,000 tons and 6,589,200 tons, respectively. At an assumed overall recovery of 68 percent after mining and conventional cleaning, the recoverable merchantable reserves would be 10,625,000 tons from the properties controlled by United Electric, and 4,480,700 tons from the adjacent properties, a total of 15,105,700 tons.

Overburden Characteristics

The soft, unconsolidated surface material underlying Gin Ridge and the slopes of Grindstone and Willow Creeks usually ranges from 15 to 25 feet in thickness. The interval from the base of this soft material down to the coal bed commonly consists of a hard gray shale, frequently sandy, and occasionally containing a bed of hard sandstone. This sedimentary, consolidated material would have to be broken by blasting before removal by stripping equipment.

Overburden Ratios

With a weighted average thickness of overburden of 53.44 feet within the United Electric properties and of 58.83 feet within the adjoining properties, the ratios of cubic yards of overburden to ton of merchantable coal would be 29.91 and 33.62, respectively.

Quality

The available analyses of the coal bed within the United Electric properties indicate that Coal No. 2 in the Industry Field is approximately similar in quality to the No. 2 coal elsewhere in this area except that it is notably higher in sulfur content.

Conclusions

The Industry Field has been well drilled, so that the available information concerning its stripping characteristics and other attributes is specific and comprehensive. With reserves of somewhat irregular coal continuity and occurrence, and with high overburden ratios, together with no better than average quality, at best, we consider the strip-mining potential of this area as distinctly marginal. These reserves, in our opinion, would not be competitive in the foreseeable future with reserves now being mined or held for future operation elsewhere in Illinois, Indiana and West Kentucky.

South of the Industry Field, Toward the Town of Rushville, Illinois

Coal Bed Location and Occurrence

The specific areas of interest that pertain to the above heading of a coal field "South of the Industry Field Toward the Town of Rushville, Illinois", consist of two isolated tracts in Schuyler County in which United Electric obtained a few land properties which were drilled for exploratory purposes and then relinquished. One such tract is situated in Sections 15 and 14, Township 3 North, Range 3 West, one mile south of the southern margin of the Industry Field proper. The second such tract is contained within Sections 4, 8 and 9, Township 2 North, Range 2 West, approximately seven miles southeast of the first tract and five miles northwest of the town of Rushville.

There were 15 drill holes put down in and near the properties in Sections 15 and 14. Only two of these holes encountered the Illinois No. 2 coal bed at its proper horizon and normal thickness. The other drill holes were negative, and were either started below the horizon of the No. 2 coal or encountered No. 2 coal in less than full thickness.

There were 14 drill holes put down within and near the properties in Sections 4, 8 and 9, all of which were negative with the maximum coal thickness in any such holes being 19 inches. Most of these holes were sufficiently deep to indicate that the No. 2 coal horizon was definitely missing.

Conclusions

The region extending south and southeast of the Industry Field toward Rushville, Illinois, as indicated by the exploration work done by United Electric, is obviously unsuitable for further consideration for mining.

Augusta Field, Located Approximately Ten Miles West of the Industry Field

Coal Bed Location and Occurrence

The Augusta Field is located in Hancock and Schuyler Counties immediately south of the town of Augusta, approximately ten miles southwest of the Industry Field. While this field lacks specific delineation it occupies southern portions of Ranges 6 West, 5 West and 4 West, all in Township 3 North, and major portions of Ranges 6 West, 5 West and 4 West, all in Township 2 North. Within this area the Illinois No. 2 coal bed intermittently underlies a broad upland area between westward-flowing headwaters of drainage systems flowing ultimately into the Mississippi River near Quincy and southeastward-flowing streams draining into the Illinois River. The eastern portion of the upland area is irregularly dissected by Williams and Cedar Creeks. While there has been local stripping in stream bottoms just south of the Augusta area, the actual coal outcrop is seldom exposed. Indications of local mine operations along the outcrop lines are relatively infrequent, suggesting difficulties in access or operation.

While ranging where present from 24 to as much as 34 inches in thickness, the general average thickness appears to be about 28 inches. The information available from drilling suggests that the coal bed is not uniformly present along the horizon where it should be encountered. It abruptly disappears under level uplands for irregular distances. It sometimes occurs on one side of a tributary stream but not on the other.

The No. 2 coal bed is occasionally underlain at a vertical interval of about 20 feet by a very irregular lower bed which appears to range from 14 to 24 inches in thickness. Analyses of this lower bed indicate abnormally high contents of ash and sulfur and this bed is not considered as any portion of the potentially strippable Augusta Field.

Estimated Reserves

Although the overall area is large, the amount of drilling is too insufficient, and the presence of areas of missing coal too strongly suggested, to permit any estimates of reserves. The apparent outcrop of the bed across the broad western portions of the field is very deep, with a cover thickness of approximately 50 feet where stripping would have to begin. In such areas the thickness of overburden increases rapidly to 75 and 100 feet.

Overburden Characteristics

The soft, unconsolidated material at the surface of the Augusta area is generally quite thin, ranging up to 20 feet in thickness but

generally averaging about 10 feet. The sedimentary strata between the base of this soft material down to the coal bed generally consist of a hard sandy shale, frequently containing one or more beds of hard sandstone ranging up to 15 feet in thickness. The stratified portion of the overburden above the coal would require relatively heavy blasting before removal by stripping equipment.

Overburden Ratios

While specific overburden ratios within the Augusta Field as a whole cannot be determined because of the lack of information on coal-bed occurrence within the field, it is probable that it would be prevailingly high.

Quality

The available analyses of the coal bed within the Augusta Field indicate that the coal is generally similar in quality to that of No. 2 coal elsewhere in this area.

Conclusions

The Augusta Field has been but sparsely drilled, so that there is not sufficient information for determining its operating characteristics. With difficult overburden characteristics and high overburden ratios, together with no better than average quality, we consider the strip-mining potential of this area as inferior. The reserves, in our

opinion, would not be competitive in the foreseeable future with reserves now being mined or held for future operation elsewhere in Illinois, Indiana and West Kentucky.

Meredosia-Mount Sterling Area,
Located in Brown County, Illinois

The combination of place names in the above title is misleading in that the Mount Sterling (Ripley) area in Brown County is on the west side of the Illinois River while the Meredosia area is separately located a substantial distance south of Mount Sterling on the eastern side of the Illinois River in Morgan and Scott Counties.

Ripley-Mount Sterling Area,
Located in Brown County, Illinois

Coal Bed Location and Occurrence

The Ripley Field (Ripley being approximately six miles northeast of Mount Sterling) consists of scattered properties in the southern portion of Township 1 North, Range 2 West, north of Crooked Creek, and of a relatively small, compact area south of Crooked Creek in the southwestern corner of the same township. Both of these two separate areas are dissected by tributary channels flowing into Crooked Creek. There has been but little local mining in this field.

Where present, the No. 2 coal bed hovers around 24 inches in thickness. This coal is either quite erratic in occurrence or too deep to be considered as strippable in the properties north of Crooked Creek. While apparently uniform in occurrence south of the Creek the available area is small, with the coal bed not only being thin but going rapidly under deep cover south and west of the prospective area.

Estimated Reserves

The area north of Crooked Creek is too erratic in coal occurrence to permit any estimate of reserves. The small area south of the Creek contains approximately 2 million tons of recoverable coal but would have a high overburden ratio because of its relative thinness.

Overburden Characteristics

The soft surface material in the area south of Crooked Creek is generally thin so that the normal interval of sandy shale down to the top of the coal bed would have to be blasted prior to stripping.

Quality

The analysis of one drill core indicates that the No. 2 coal at Ripley is approximately similar in quality to No. 2 coal elsewhere in this field.

Conclusions

The area adjacent to the town of Ripley south of Crooked Creek has been well drilled, but with the thinness of the coal and high overburden ratio, and with its limited extent, we consider the strip-mining potential of this area as inferior. The reserves, in our opinion, would not be competitive in the foreseeable future with reserves now being mined or held for future operations elsewhere in Illinois, Indiana and West Kentucky.

Meredosia Area, in Morgan and Scott Counties, Illinois

Coal Bed Location and Occurrence

The Meredosia field was explored over a considerable geographic area by conducting drilling operations in small, scattered properties located in Range 12 West, Township 16 North, Ranges 13 and 12 West, Township 15 North, and Ranges 13 and 12 West, Township 14 North. This overall area is approximately 16 miles north-south, and seven miles east-west in extent. The town of Meredosia is on the Illinois River, about five miles west of the northern portion of the explored area. The coal-bearing area occupies the upland facing the broad Illinois River valley which is heavily dissected by westward-flowing creeks and tributaries. Local mining operations are few and scattered, being located mainly in the deeper drainage valleys near small towns.

While probably present throughout the area, the No. 2 coal is prevailingly deep, ranging from 50 to 100 feet or more over broad areas. The coal bed ranges from 24 to 31 inches in normal thickness. The overburden generally consists of up to 75 feet of soil and glacial deposits, and the sedimentary strata between the bottom of the glacial deposits and the top of the coal bed commonly contain varying thicknesses of sandstone.

Conclusions

While the work done by United Electric in the Meredosia area was primarily of an exploratory nature, the results are sufficient to indicate that the area is not potentially strippable because of the prevailingly excessive depth of overburden.

Spring Lake Township Area, Tazewell County

Coal Bed Location and Occurrence

The portion of Spring Lake Township (Ranges 7 and 6 West, Township 24 North) designated as the Spring Lake Township Area is located in the essentially flat bottom lands comprising the Illinois River valley south of the channel of the Illinois River. The coal bed does not outcrop nor has it been mined in the vicinity of this area. It is being mined, however, north of the river in Townships 6 and 7 North, Ranges 5 and 6 East, by the United Electric Coal Companies at their Banner Mine.

The No. 2 coal bed south of the river in Spring Lake Township appears to be very limited in areal extent. The thickness of coal encountered in six drill holes ranged from 17 to 29 inches, with an average of 22 inches. Where it was found to be present, the bed underlies a veneer of water-bearing valley sediments approximately 20 feet in thickness, below which there is a hard gray shale, sometimes sandy, to the top of the coal bed. Elsewhere within the area explored, drilling encountered up to 48 feet of unconsolidated strata, suggesting that the coal bed does not uniformly underlie the valley floor but was either eroded or never deposited in irregular areas.

The amount of drilling is too insufficient, and the presence of areas of missing coal too strongly suggested, to permit any estimates of reserves.

Quality

The available analyses indicate that this coal is approximately similar in quality to No. 2 coal elsewhere in this field except that it is notably higher in sulfur content.

Conclusions

The Spring Lake Township area is too limited in extent, without any indications of potential expansion in total area, to suggest any possibilities of commercial operation.

Salt Fork Field, Located Near Catlin, Illinois

Coal Bed Location and Occurrence

The Catlin Field is located largely in the south-central portion of Township 19 North, Range 12 West (Vermilion County), just northwest of the town of Catlin, which is approximately six miles southwest of the city of Danville, Illinois. At this location the Illinois No. 7 coal bed underlies a comparatively flat upland just south of Salt Fork at its confluence with the Vermilion River. Some of the earliest commercial strip mining in Illinois took place in the flat bottom lands of Salt Fork and Vermilion River. There is an active stripping operation on the north side of the Vermilion River approximately three miles west of Danville.

During and shortly after its exploration of the Catlin Field, United Electric also prospected the valley of Vermilion River approximately two miles north of the then northernmost limit of the old stripped-out area. A few drill holes were also put down in upland terrain approximately four miles west of Catlin.

The No. 7 coal bed under these three scattered areas ranges from 68 to 76 inches in thickness, with a general average of 6'0". It is persistent within the explored areas but lies under relatively high cover in all of the three areas thus tested.

Estimated Reserves

The drilling programs were too limited in extent to determine specific estimates of reserves, although the Catlin area is obviously large. The original United Electric Catlin Field, in fact, plus extensive areas east and west of this field, are now in the hands of another company, representing inactive reserves.

Overburden Characteristics and Ratios

The overburden strata, both in the river bottoms to the north, and in the upland areas south of Vermilion River, generally consist of relatively thin surface material underlain by shales, sandy shales and sandstones. Such overburden would have to be blasted before removal by stripping equipment. The thickness of overburden in the areas drilled was generally over 80 feet, ranging up to 110 feet in the Vermilion River flats, up to 120 feet in the Catlin area proper, and up to 165 feet in the area four miles west of Catlin. Overburden ratios would approximate 25:1 or more.

Quality

The No. 7 coal in the general Danville Area is slightly higher in ash and slightly lower in sulfur as compared with most other Illinois coals.

Conclusions

The Catlin Field is no longer available, but with its high overburden ratios, would be considered as distinctly marginal when compared with most coal reserves now being mined or held for future operations elsewhere in Illinois, Indiana and West Kentucky.

Fidelity Mine Deep Coal

Coal Bed Location and Occurrence

The Fidelity "Deep" area is located in the southeastern part of Section 27 and the eastern part of Section 28, Township 6 South, Range 2 West (Perry County), and in the northwestern corner of Section 2 and the northeastern corner of Section 3, Township 7 South, Range 2 West (Jackson County). Lying between what will eventually become the final limit of stripping of the Fidelity Mine at the approximate 85-foot cover line as its western boundary and the large Kathleen underground mine as its eastern boundary, the area is approximately 1.75 miles north-south and 0.625 miles east-west in extent.

The Illinois No. 6 coal in the Fidelity "Deep" area is persistent ranging from 66 to 110 inches in thickness.

Estimated Reserves

There are approximately 794 coal acres within the Fidelity "Deep" tract. With a weighted average thickness of 83.67 inches, the reserves of raw coal in place before mining would be 9,965,000 tons. At an

assumed overall recovery of 72 percent after mining and conventional cleaning, the recoverable merchantable reserves would be 7,175,000 tons.

Overburden Characteristics

The overburden commonly consists of up to 58 feet of unconsolidated surface and glacial material, below which the sedimentary strata consist of shales, sandy shales and occasionally sandstone. A persistent massive limestone bed, ranging from one to 14 feet in thickness and lying from 3 feet to 25 feet above the coal bed, is also included in the overburden. Such strata are difficult to handle and would require selective and heavy blasting before removal by stripping equipment.

Overburden Ratios

With a weighted average overburden thickness of 89.48 feet, the ratio of cubic yards of overburden to ton of merchantable coal would be 15.98:1.

Quality

While not specifically tested, the quality of the No. 6 coal in this area is considered to be essentially the same as that of the No. 6 coal being mined at the Fidelity Mine.

Conclusions

The Fidelity "Deep" field has been well drilled, so that the available information concerning its stripping characteristics is specific and comprehensive. With its difficult overburden characteristics and high overburden ratio, we consider that there is virtually no strip-mining potential for this area. It would be impossible to strip mine these coal reserves at a cost comparable to the coal production costs of the other stripping operations and reserves yet to be mined in the Belleville District.

Economics and Reserve Position
Bituminous Coal Mining
Illinois, Indiana and West Kentucky

For some time, strip mining has been providing an increasing share of coal output in the Tri-State Area. Table 1 shows annual production for the years 1949 through 1967 for strip mines, underground mines and all mines. The proportion mined by stripping has increased from 39.90 percent in 1949 to 64.94 percent in 1967. Production from underground mines declined from 60,461,000 tons in 1950 to 38,596,000 tons in 1961. Since that time, underground production has gradually increased to a level of 45,666,000 tons in 1967.

Bulletin 1252-C of the U. S. Geological Survey entitled "Stripping-Coal Resources of the United States" (1968), contained this summary of recent work by the Illinois Geological Survey:

". . . in 1955 the Illinois Geological Survey began a new program of study of stripping coal that has yielded five reports to date (Smith, 1957, 1958, 1961; Smith and Berggren, 1963; Reinertsen, 1964). On the basis of work completed and in progress, J. A. Simon (written commun., Sept. 28, 1966) has concluded that the remaining stripping-coal resources of Illinois as of January 1, 1966, in beds 18 inches or more thick and at a maximum depth of 150 feet, total 21,223 million tons. Simon also concluded that the original resources within the same parameters totaled about 23,000 million tons."

With a record of past growth and what might seem to be an assured resource base on which to build, it would appear that strip mining would continue its record of growth. Actually, estimates of strippable coal reserves of Illinois are misleading. Strippable coal as defined by the Illinois Geological Survey includes coal seams that are 18 inches or more thick with an overburden not more than 150-feet thick. A substantial proportion of the strippable reserves as thus defined are not economically recoverable as of the present time and may never be economically recoverable. In a paper entitled "An Evaluation of Illinois Coal Reserves Estimates," presented at the 76th Annual Meeting of the Illinois Mining Institute in Springfield, Illinois, October 25, 1968, by J. A. Simon and W. H. Smith of the Illinois Geological Survey, these comments were made:

"Use of the words minable and strippable as applied to Illinois reserve studies, although defined in the studies, has been too often literally interpreted . . .. Some misuse of these data has been made."

The concluding remarks of the paper include this statement:

"Although total remaining coal reserves of Illinois are considered to be conservative as defined (emphasis added) in studies to date, minable or strippable reserves based on these data will be much smaller (emphasis added) if defined by greater minimum thickness or modified by definitions of economic minability."

In a paper entitled "Coal Strip Mining - Is It Reaching A Peak?", by Hubert E. Risser, Assistant Chief and Principal Mineral Economist, Illinois Geological Survey, presented at the Fall Meeting of the Society of Mining Engineers in Minneapolis, Minnesota, September 18, 1968, the following summary was presented:

"For half a century the percentage of coal production provided through strip mining has steadily increased. Recent trends indicate that a peak in percentage, if not in tonnage, is being approached. Important among the reasons for this is the decline in economic advantage enjoyed by strip mining compared to underground mining. Among the factors contributing to this decline are the following:

"1. Decrease in the margin of advantage in manpower requirements held by strip mining.

"2. Increase in depth and volume of overburden necessitating larger equipment and investment of more capital.

"3. Increasing scarcity of reserve blocks of land big enough to support extensive mining operations.

"4. Increasingly stringent legislation for reclamation of stripped land and the resulting higher cost of reclamation.

"5. Increasing cost of land surface rights.

"In the eastern part of the United States there has already been a peaking and decline in the relative importance of strip mining in some major coal producing states. Although it is not clear at what point the pressures discussed above will cause a peaking for the region as a whole, the trends indicate that this definitely is on the way."

In order to give a perspective on trends in the Tri-State Area Tables 2, 3 and 4 present information on new coal mines which were placed in operation or announced during the period from 1959 to date. As shown in Table 2, which presents data on deep coal mines, the Orient No. 5 Mine of Freeman Coal Mining Corporation and Mine No. 21 of Old Ben Coal Corporation were placed in operation in 1959. After 1959, no new deep mines were developed until 1964. Since that time, 18 deep mines have been placed in operation or announced. As shown in Table 4, the total number of mines announced or placed in operation for the period was 20 mines having an approximate annual capacity of 44.5 million tons.

Table 3 presents similar information on strip coal mines. Since 1959, 16 new mines having an approximate annual capacity of 34.3 million tons have been placed in operation or announced. The most recent mine to be announced was the Leahy Mine of Ayrshire Collieries Corporation. This mine is in Perry County, Illinois, and will strip the reserves in the Denmark Field. These reserves are known in the industry as the last undeveloped major reserve of strippable coal in the Tri-

State Area and we doubt that any new comparable strip operations can be developed in the Tri-State Area.

We specifically point out the strip mines listed on Table 3 are based on coal reserves which had been in the hands of the operating company or precedessor companies for many years before development commenced. For example, the Denmark lands, on which the Ayrshire Collieries Corporation Leahy Mine will be developed, were assembled into a block in about 1927 by a predecessor company.

The summary shown on Table 4 does indicate the way in which underground coal production is increasingly supporting the growth in production in the Midwest. This trend must continue. In addition to the deep mines listed, we know of several underground operations which will definitely be developed but have not been announced. In contrast we know of no major strip mine which will be developed but has not been announced.

Counsel for defendants in United States v. General Dynamics, et al. have provided us with the following schedule of midwestern coal reserves controlled by producing companies (and excluding reserves controlled by Standard Oil Company (New Jersey) or affiliates):

Midwestern Coal Reserves Controlled by Producers
(Million Tons)

	Dedicated to Existing Mines	Other Reserves	Total
Strip	1,148	646	1,794
Deep	1,133	6,412	7,545
	2,281	7,058	9,339

In comparing these resource bases with the production of strip and deep coal in the Tri-State Area (84.6 million tons strip and 45.7 million tons deep, according to the most recent U. S. Bureau of Mines statistics), the index of remaining life for strip coal would be 21 years and for deep coal 165 years. Actually, of course, the production of any natural resource does not continue at a level rate and then cease. Over a period of time the plot of production will assume a bell-shaped curve with production increasing, gradually reaching a peak, and then declining. It is evident that reserves of strippable coal are limited in relation to the present level of production. For this reason we believe that peak production of strip coal will be reached within a very short time and a gradual decline will ensue thereafter. Meanwhile, there will be substantial growth in underground production. In 1980, we project that 75 percent of production in the Tri-State Area will come from deep mines.

An obvious question is whether additional strippable coal reserves can be found in the Tri-State Area to add to the relatively limited strip reserves shown in the above table.

The most important factor in determining whether coal reserves are economically recoverable by stripping is the overburden ratio; that is the cubic yards of overburden which must be removed to uncover a ton

of coal. Obviously, the reserves lying under shallower cover are the most attractive and are mined first. Overburden ratios for remaining reserves are increasing.

Tables 5a, 5b and 5c are presented to show the effect of overburden ratios and other factors affecting the economics of strip mining in the Midwest. The annual production assumed is 2,000,000 tons and four hypothetical mines are presented having overburden ratios of 12.6, 14.7, 19.6 and 25.2 cubic yards per ton. The life of each mine is assumed to be 20 years. It is assumed that for all four mines stripping equipment capable of digging to a maximum height of 100 feet is employed. The greater overburden ratio is assumed to be due to lesser coal thickness. As shown, the coal acres required vary from 5,128 acres for the 12.6 ratio to 10,417 acres for the 25.2 ratio. These are substantial areas in any case, and acquisition of blocks of such size is extremely difficult if not impossible. Even if lands of such size were available, land costs are steadily rising. For our studies we have assumed an average cost of $500 per acre. In many areas costs are as much as $800 to $1,000 per acre.

We assume that a single stripping shovel would uncover all of the overburden. The capacity of the stripping shovel varies from 90-cubic yards for the 12.6 ratio to 180-cubic yards for the 25.2 ratio. This is the largest stripping shovel which has yet been built. As can be seen from Table 5a, the cost of the stripping shovel is the major element of capital cost for a strip mine. The total initial investment for all plant and equipment and coal lands for the strip mines increases

from \$6.39 per annual ton for the 12.6 ratio to \$11.75 per annual ton for the 25.2 ratio.

Table 5b shows the estimated costs of production for the four hypothetical mines. The direct operating cost per yard of material moved is estimated to be 5.5 cents per cubic yard for the 90-cubic yard shovel and 5.0 cents per cubic yard for the 105-cubic yard shovel. The cost per yard for the 140- and 180-cubic yard shovels is assumed to also be 5.0 cents per cubic yard. The increased size of the shovels does not result in reduced costs per yard.

The total cost of production including depreciation and depletion increases from \$2.836 for the 12.6 ratio to \$4.128 for the 25.2 ratio. In order to place these costs in further perspective, we have calculated the sales realization which would be required to make the hypothetical mines attractive coal mine investments. We have assumed a rate of return of 12 percent on investment. The realization necessary on this basis varies from \$3.635 for a 12.6 ratio to \$5.721 for a 25.2 ratio. The detail on these calculations is shown on Table 5c. In 1967 the average values per ton for mines in Illinois, Indiana and West Kentucky were \$3.88, \$3.99 and \$3.42, respectively.1/ From these data it can be seen that the prevailing level of sales realizations would not permit economically viable mining of coal at high overburden ratios. Under average conditions we would estimate a maximum economic ratio in the Tri-State Area as of the present time of about 18-cubic yards per ton.

1/ U. S. Bureau of Mines Minerals Yearbook, 1967.

There are, of course, instances where coal under somewhat heavier ratio can be mined economically because of overburden which does not require shooting and/or because of high sales realization due to favorable transportation arrangements.

The relationship shown between overburden ratio and sales realization necessary for an adequate return on investment is essentially linear. For each one point increase in ratio an additional 16.5 cents per ton in realization is necessary for an adequate return.

The investment required for underground mining is substantially less than for strip mining under heavy overburden. As of the present time, the investment per annual ton for an underground mine in the Tri-State Area approximates $5.00 to $6.00. This compares with investments per annual ton for the hypothetical strip mines of from $6.39 to $11.75. As overburden ratios increase, a point is reached where underground mining is cheaper than strip mining.

Commercial coal producers in Illinois, Indiana and West Kentucky have been faced for some time with a deteriorating strip reserve position. Reserves held by operating companies are inadequate to support a sufficient number of new mines which could produce at competitive costs. Such existing unassigned reserves are generally characterized by higher overburden ratios and smaller blocks of land often insufficient to support economic operations. Despite diligent search, operators have been unable to find economically strippable reserves not now controlled

by others.[2] It is clear that operators will not be able to replace strip mines being worked out, let alone attempt to supply any growth in coal demand. For the industry as a whole, and for specific companies, underground coal production must not only supply the growth in coal demand, but also replace strip production as strip mines are depleted.

Ability of United Electric to Undertake Successful Deep Coal Mining

The primary deterrent to initiating deep mining for any coal or non-coal company not already having a deep-mining organization is the crucial and critical shortage of miners, supervisors and technically-trained people. During the period subsequent to World War II, the coal industry suffered from declining markets and production. Not until 1960 did the growth in the primary market, electric utilities, offset loss of other markets. The image of the industry in the 1950's was sick. Mining schools were closed because of lack of students. Ohio State, Pittsburgh, Lehigh and the University of Illinois all closed their mining departments. It is almost inconceivable that Illinois, with the largest reserves of bituminous coal in the nation, does not offer a degree in mining engineering at the University. Because of the decline in the 1950's, few miners entered the industry. Presently, there are too many employees in the upper age brackets, experienced but old, and too many in the lower age brackets, young and

2/ See our letter of July 12, 1967, attached hereto, the accuracy of which we reconfirm.

inexperienced. There are too few in between. Presently, many companies are resorting to training schools to get miners and supervisors.

Coal mining by deep methods is very specialized in comparison to surface mining. Surface mining is in many ways analagous to earth moving. Deep mining requires more expertise and expertise quite different and distinct from that required for strip mining. Deep mining also involves more risk. Generally, coal companies have relied on either strip mining or deep mining, not both. The exceptions to this have been companies of one primary type of mining which acquired or were merged with companies of the other primary type. For example, Consolidation Coal Company became both a strip-mining and deep-mining company through the merger of Pittsburgh Coal Company (deep), Christopher Coal Company (deep), Hanna Coal Company (deep and strip), Pocahontas Fuel Company (deep) and Truax-Traer Coal Company (strip). Peabody Coal Company became both strip and deep when the Sinclair Coal Company (strip) was merged into Peabody (deep). There has been a great reluctance on the part of the management of strip-mining companies to try deep mining.

In order to undertake deep mining United Electric would have had to acquire a deep-mining organization in spite of extreme shortage of competent personnel. Management would have had to accept responsibility not only for economically viable deep-mining projects, but for the safety of personnel. This latter requirement has particularly troubled managements oriented toward strip mining alone. While it is, of course,

impossible to state for certain whether or not United Electric would even have attempted to undertake deep mining, it is improbable that they could have done so successfully, and, therefore, highly unlikely that they would have tried. This would have been true even if United Electric had had the best deep-mining reserves to work with. We believe that the integration of control of United Electric and Freeman was a logical and desirable step for United Electric as a company with very limited strippable reserves and no deep-mining team.

Respectfully submitted,
PAUL WEIR COMPANY

By: J. P. Weir
J. P. Weir

TABLE 1 COAL MINE PRODUCTION (Thousand Short Tons) TABLE 1

Year	STRIP MINES				UNDERGROUND MINES				TOTAL MINES				PERCENT STRIP			
	Illinois	Indiana	West Kentucky	Total	Illinois	Indiana	West Kentucky	Total	Illinois	Indiana	West Kentucky	Total	Illinois	Indiana	West Kentucky	Total
1949	13,893	9,592	9,149	32,634	33,315	6,957	8,880	49,152	47,208	16,549	18,029	81,786	29.43	57.96	56.74	39.90
1950	17,612	10,740	11,467	39,819	38,678	9,217	12,566	60,461	56,290	19,957	24,033	100,280	31.29	53.82	47.71	39.71
1951	18,297	10,997	9,096	38,390	35,903	8,453	12,795	57,151	54,200	19,450	21,891	95,541	33.76	56.54	41.55	40.18
1952	16,705	9,773	8,845	35,323	29,085	6,577	12,336	47,998	45,790	17,350	21,181	84,321	36.48	56.33	41.76	41.89
1953	16,681	9,630	8,312	34,623	29,329	6,182	13,001	48,512	46,010	15,812	21,313	83,135	36.26	60.90	39.00	41.65
1954	16,454	8,513	9,606	34,573	25,517	4,887	12,844	43,248	41,971	13,400	22,450	77,821	39.74	63.53	42.79	44.43
1955	18,676	11,182	11,741	41,599	27,256	4,967	14,569	46,792	45,932	16,149	26,310	88,391	40.66	69.24	44.63	47.06
1956	19,675	11,914	14,400	45,989	28,427	5,175	15,142	48,744	48,102	17,089	29,542	94,733	40.90	69.72	48.74	48.44
1957	19,999	10,891	15,228	46,118	26,994	4,950	13,744	45,688	46,993	15,841	28,972	91,806	42.56	68.75	52.56	50.23
1958	20,522	10,319	16,236	47,077	23,373	4,703	11,792	39,868	43,895	15,022	28,028	86,945	46.75	69.53	57.93	54.14
1959	21,912	10,159	17,380	49,451	23,526	4,644	12,205	40,375	45,438	14,803	29,585	89,826	48.22	72.15	58.75	55.05
1960	22,671	10,785	17,689	51,145	23,307	4,753	12,869	40,929	45,978	15,538	30,558	92,074	49.31	65.38	57.89	55.55
1961	22,786	10,497	18,899	52,182	22,418	4,609	11,569	38,596	45,204	15,106	30,468	90,778	50.62	69.49	62.03	57.48
1962	24,585	11,309	20,232	56,126	23,902	4,400	11,646	39,948	48,487	15,709	31,878	96,074	50.40	71.94	63.47	58.42
1963	27,287	10,939	22,905	61,131	24,449	4,160	12,666	41,275	51,736	15,099	35,571	102,406	52.74	72.45	64.39	59.69
1964	29,988	11,622	25,175	66,785	25,034	3,453	12,600	41,087	55,022	15,075	37,775	107,872	54.50	77.44	66.64	61.91
1965	32,670	13,210	25,733	71,613	25,814	2,355	13,409	41,578	58,484	15,565	39,142	113,191	55.86	84.87	65.74	63.27
1966	36,113	15,465	27,219	78,797	27,458	1,861	14,903	44,222	63,571	17,326	42,122	123,019	56.80	89.26	64.62	64.05
1967	37,185	17,131	30,282	84,598	27,948	1,641	16,077	45,666	65,133	18,772	46,390	130,264	57.09	91.26	65.28	64.94

Source: U. S. Bureau of Mines, Minerals Yearbooks.

TABLE 2

NEW COAL MINES
PLACED IN OPERATION OR ANNOUNCED
TRI-STATE AREA
ILLINOIS, INDIANA, WEST KENTUCKY

D E E P

Year	Location	Company	Mine Name	Approximate Annual Tons	Status
1959	Illinois	Freeman Coal Mining Corp.	Orient No. 5	1,600,000	Active
1959	Illinois	Old Ben Coal Corp.	Mine No. 21	3,000,000	Active
1964	Illinois	Truax-Traer Coal Co.	Coffeen	1,200,000	Active
1965	Illinois	Old Ben Coal Corp.	Mine No. 24	3,000,000	Active
1966	Illinois	Inland Steel Co.	Sesser	3,000,000	Active
1966	Illinois	Old Ben Coal Corp.	Mine No. 26	3,000,000	Active
1966	West Kentucky	Bell & Zoller Coal Co.	Zeigler No. 9	1,500,000	Active
1966	West Kentucky	Island Creek Coal Co.	Hamilton	5,200,000	Active
1967	West Kentucky	Webster County Coal Corp.	Dotiki	600,000	Active
1967	Illinois	Freeman Coal Mining Corp.	Orient No. 6	3,300,000	Active
1967	Illinois	Peabody Coal Co.	Eagle No. 1	2,000,000	Active
1967	West Kentucky	Peabody Coal Co.	River Queen	1,250,000	Active
1967	Illinois	Peabody Coal Co.	Midwest	500,000	Active
1968	West Kentucky	Pittsburg & Midway Coal Mining Co.	Drake No. 1 & No. 2	1,500,000	Active
1968	West Kentucky	Black Tam Mining Co.	Tam No. 2	800,000	Under Construction
1969	West Kentucky	Island Creek Coal Co. (TVA)	Providence	1,500,000	Under Construction
1970	Illinois	Peabody Coal Co.	Eagle No. 2	3,000,000	Under Construction
1971	Illinois	Monterey Coal Co. (Humble)	Macoupin Co.	2,500,000	Under Construction
1971	West Kentucky	Peabody Coal Co. (TVA)	Camp No. 1	3,000,000	Projected
1971	West Kentucky	Peabody Coal Co. (TVA)	Camp No. 2	3,000,000	Projected
	Total			44,450,000	

Source: Keystone News Bulletins, McGraw-Hill, Inc.

TABLE 3

NEW COAL MINES
PLACED IN OPERATION OR ANNOUNCED
TRI-STATE AREA
ILLINOIS, INDIANA, WEST KENTUCKY

STRIP

Year	Location	Company	Mine Name	Approximate Annual Tons	Status
1960	Illinois	Stonefort Coal Mining Co.	Allendale	600,000	Active
1960	Illinois	United Electric Coal Companies	Banner	600,000	Active
1962	West Kentucky	Peabody Coal Co.	Sinclair	4,000,000	Active
1962	Illinois	Ayrshire Collieries Corp.	Sunspot	800,000	Active
1963	West Kentucky	Peabody Coal Co.	Homestead	2,000,000	Active
1964	Illinois	Southwestern Illinois Coal Corp.	Captain	5,000,000	Active
1965	Indiana	Peabody Coal Co.	Hawthorne	1,500,000	Active
1966	Illinois	Truax-Traer Coal Co.	Burning Star No. 3	1,800,000	Active
1967	Indiana	Ayrshire Collieries Corp.	Ayrcoe	700,000	Active
1967	Illinois	Peabody Coal Co.	Eagle	1,000,000	Active
1968	Illinois	Truax-Traer Coal Co.	Norris No. 1	2,800,000	Active
1968	Illinois	Peabody Coal Co.	Elm	3,000,000	Active
1968	Indiana	Peabody Coal Co.	Dugger	2,500,000	Active
1970	West Kentucky	Ayrshire Collieries Corp. (TVA)	Ayrgem	2,500,000	Under Construction
1971	Indiana	Peabody Coal Co.	Universal	3,000,000	Under Construction
1971	Illinois	Ayrshire Collieries Corp. (Denmark)	Leahy	2,500,000	Under Construction
	Total			34,300,000	

Source: Keystone News Bulletins, McGraw-Hill, Inc.

TABLE 4

SUMMARY
NEW COAL MINES
ILLINOIS, INDIANA, WEST KENTUCKY

	1959		1960		1961		1962		1963		1964		1965		1966		1967		1968		1969	
	No. of Mines	Capacity Thousand Tons	No. of Mines	Capacity Thousand Tons	No. of Mines	Capacity Thousand Tons	No. of Mines	Capacity Thousand Tons	No. of Mines	Capacity Thousand Tons	No. of Mines	Capacity Thousand Tons	No. of Mines	Capacity Thousand Tons	No. of Mines	Capacity Thousand Tons	No. of Mines	Capacity Thousand Tons	No. of Mines	Capacity Thousand Tons	No. of Mines	Capacity Thousand Tons
DEEP - Illinois	2	4,600	-	-	-	-	-	-	-	-	1	1,200	1	3,000	2	6,000	3	5,800	-	-	-	-
Indiana	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
West Kentucky	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	6,700	2	1,850	2	2,300	1	1,500
Total	2	4,600	-	-	-	-	-	-	-	-	1	1,200	1	3,000	4	12,700	5	7,650	2	2,300	1	1,500
STRIP - Illinois	-	-	2	1,200	-	-	1	800	-	-	1	5,000	-	-	1	1,800	1	1,000	3	8,300	-	-
Indiana	-	-	-	-	-	-	-	-	-	-	-	-	1	1,500	-	-	1	700	-	-	-	-
West Kentucky	-	-	-	-	-	-	1	4,000	1	2,000	-	-	-	-	-	-	-	-	-	-	-	-
Total	-	-	2	1,200	-	-	2	4,800	1	2,000	1	5,000	1	1,500	1	1,800	2	1,700	3	8,300	-	-
GRAND TOTAL	2	4,600	2	1,200	-	-	2	4,800	1	2,000	2	6,200	2	4,500	5	14,500	7	9,350	5	10,600	1	1,500

Source: Keystone News Bulletins, McGraw-Hill, Inc.

TABLE 4

1965 Capacity Thousand Tons	1966 No. of Mines	1966 Capacity Thousand Tons	1967 No. of Mines	1967 Capacity Thousand Tons	1968 No. of Mines	1968 Capacity Thousand Tons	1969 No. of Mines	1969 Capacity Thousand Tons	1970 No. of Mines	1970 Capacity Thousand Tons	1971 No. of Mines	1971 Capacity Thousand Tons	Total No. of Mines	Total Capacity Thousand Tons
3,000	2	6,000	3	5,800	-	-	-	-	1	3,000	1	2,500	11	26,100
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	2	6,700	2	1,850	2	2,300	1	1,500	-	-	2	6,000	9	18,350
3,000	4	12,700	5	7,650	2	2,300	1	1,500	1	3,000	3	8,500	20	44,450
-	1	1,800	1	1,000	3	8,300	-	-	-	-	1	2,500	10	20,600
1,500	-	-	1	700	-	-	-	-	-	-	1	3,000	3	5,200
-	-	-	-	-	-	-	-	-	1	2,500	-	-	3	8,500
1,500	1	1,800	2	1,700	3	8,300	-	-	1	2,500	2	5,500	16	34,300
4,500	5	14,500	7	9,350	5	10,600	1	1,500	2	5,500	5	14,000	36	78,750

TABLE 5a

ECONOMIC STUDY
OF MIDWESTERN STRIP MINING
MINES PRODUCING 2,000,000 TONS ANNUALLY

Overburden Ratio		12.6	14.7	19.6	25.2
Recoverable Coal Reserves	(Thousand Tons)	40,000	40,000	40,000	40,000
Life of Mine	(Years)	20	20	20	20
Annual Production	(Thousand Tons)	2,000	2,000	2,000	2,000
Coal Thickness	(Inches)	69	59	44	34
Recovery	(Tons Per Acre)	7,800	6,600	4,940	3,840
Coal Acres Required		5,128	6,061	8,097	10,417
Initial Investment in Coal Lands, assuming average cost of $500 per acre and that 50 percent of lands would be acquired initially	(Thousands)	$ 1,282	$ 1,515	$ 2,024	$ 2,604
Annual Investment Required to purchase remaining 50 percent of lands	(Thousands)	$ 64	$ 76	$ 101	$ 130
Data on Stripping Equipment					
Maximum Digging Height	(Feet)	100	100	100	100
Average Digging Height	(Feet)	60	60	60	60
Annual Cubic Yards Required	(Thouands)	25,600	29,400	39,200	50,400
Size of Bucket on Stripping Shovel	(Cubic Yards)	90	105	140	180
Capital Costs					
Plant and Equipment					
Stripping Shovel	(Thousands)	$ 6,500	$ 9,000	$12,000	$15,000
All Other Equipment-Haulage Trucks, Coal Loaders, Bulldozers, Overburden Drills, Preparation Plant	(Thousands)	5,000	5,300	5,600	5,900
Total Initial Investment	(Thousands)	$11,500	$14,300	$17,600	$20,900
Replacement of Short-Life Equipment Over Life of Mine	(Thousands)	4,500	5,100	5,700	6,300
Total Depreciable Equipment	(Thousands)	$16,000	$19,400	$23,300	$27,200
Unit Depreciation	(Per Ton)	$0.400	$0.485	$0.583	$0.680
Total Initial Investment					
Plant and Equipment	(Thousands)	$11,500	$14,300	$17,600	$20,900
Coal Lands	(Thousands)	1,282	1,515	2,024	2,604
Total	(Thousands)	$12,782	$15,815	$19,624	$23,504
Initial Investment Per Annual Ton		$6.39	$7.91	$9.81	$11.75

TABLE 5b

ECONOMIC STUDY
OF MIDWESTERN STRIP MINING
MINES PRODUCING 2,000,000 TONS ANNUALLY

Overburden Ratio		12.6	14.7	19.6	25.2
Cost Per Yard					
Stripping (Labor and Supplies)	(Per Yard)	$0.055	$0.050	$0.050	$0.050
Bankshooting (Labor and Supplies)	(Per Yard)	0.015	0.015	0.015	0.015
Total Operating Cost	(Per Yard)	$0.070	$0.065	$0.065	$0.065
Cost of Production					
Stripping and Bankshooting	(Per Ton)	$0.882	$0.956	$1.274	$1.638
Coal Loading	(Per Ton)	0.120	0.130	0.140	0.160
Coal Haulage	(Per Ton)	0.250	0.260	0.300	0.350
Coal Preparation	(Per Ton)	0.220	0.220	0.220	0.220
Other Operating Costs	(Per Ton)	0.350	0.360	0.380	0.400
Welfare Fund	(Per Ton)	0.400	0.400	0.400	0.400
Sales and Administration	(Per Ton)	0.150	0.150	0.150	0.150
Total Cash Costs	(Per Ton)	$2.372	$2.476	$2.864	$3.318
Depreciation	(Per Ton)	0.400	0.485	0.583	0.680
Depletion	(Per Ton)	0.064	0.076	0.101	0.130
Total Cost of Production	(Per Ton)	$2.836	$3.037	$3.548	$4.128
Annual Net Cash Flow Required for 12 Percent DCF Return on Investment	(Thousands)	$1,711	$2,117	$2,627	$3,147
Add Average Annual Expenditures for					
Plant and Equipment	(Thousands)	225	255	285	315
Coal Lands	(Thousands)	64	76	101	130
Annual Gross Cash Flow Required	(Thousands)	$2,000	$2,448	$3,013	$3,592
	(Per Ton)	$1.000	$1.224	$1.506	$1.796
Sales Realization Required for 12 Percent Return on Investment (see TABLE 5c)	(Per Ton)	$3.635	$4.070	$4.860	$5.721

TABLE 5c

ECONOMIC STUDY
OF MIDWESTERN STRIP MINING
MINES PRODUCING 2,000,000 TONS ANNUALLY

Overburden Ratio		12.6	14.7	19.6	25.2
Sales Realization	(Per Ton)	$3.635	$4.070	$4.860	$5.721
Cost of Production	(Per Ton)	2.772	2.961	3.447	3.998
Net Profit	(Per Ton)	$0.863	$1.109	$1.413	$1.723
10 Percent of Sales Realization	(Per Ton)	$0.364	$0.407	$0.486	$0.572
50 Percent of Net Profit	(Per Ton)	0.431	0.554	0.706	0.862
Taxable Income	(Per Ton)	$0.499	$0.702	$0.927	$1.151
Income Tax @ 52.8 Percent	(Per Ton)	0.263	0.370	0.490	0.607
Income After Tax	(Per Ton)	$0.600	$0.739	$0.923	$1.116
Add Back Depreciation	(Per Ton)	0.400	0.485	0.583	0.680
Gross Cash Flow	(Per Ton)	$1.000	$1.224	$1.506	$1.796

APPENDIX

CABLE ADDRESS "WEIRCO"

PAUL WEIR COMPANY
INCORPORATED
MINING ENGINEERS AND GEOLOGISTS
(312) FINANCIAL 6-0275
20 NORTH WACKER DRIVE
CHICAGO, ILLINOIS 60606

PAUL WEIR, CHAIRMAN OF THE BOARD
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DONALD H. DOWLIN
DAVID J. KASNIK

July 12, 1967

Mr. Frank Nugent, President
Freeman Coal Mining Corporation
307 North Michigan Avenue
Chicago, Illinois 60601

Dear Mr. Nugent:

For the past forty-seven years I have been a resident of Illinois and have been in the coal industry continuously during these years. For the first sixteen years I was engaged in engineering and production for a major Illinois coal operator. For the past thirty-one years I have had my own firm of independent mining engineers serving as consultants to entities interested in coal reserves and mining.

In the tri-state area of Illinois, Indiana and West Kentucky my firm has rendered services to all of the major coal producers, to the United States Army Corps of Engineers, to the major utilities operating in this area, to the railroads, to financial institutions, to major oil companies and others. In this work we have had the opportunity to study and become familiar with the coal reserves in the hands of our clients as well as the estimates of the Illinois State Geological Survey.

For the purposes of demonstrating the ultimate availability of strippable coal reserves, you have asked our opinion as to the availability of areas in the State of Illinois of strippable coal reserves containing as much as 10 to 20 millions of recoverable tons and not now owned or under option to coal operators, with emphasis on the Fulton-Peoria-Stark-Knox Counties fields. The only reserves in Illinois that can be considered for strip mining are found in Seams No. 5, No. 2 and No. 6, and our discussion is limited to those seams.

In the Fulton-Peoria area, the No. 5 Seam has been the one most widely mined. Remaining strippable reserves of any consequence in this seam are owned and/or controlled by two operating companies, United Electric and a competitor.

PAUL WEIR COMPANY

Mr. Frank Nugent

July 12, 1967
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Some production has come from the No. 6 Seam, principally in the northern part of the county (Fulton). The strippable coal reserves extend north into Knox County. Mining in the No. 6 Seam is substantially different from that in the No. 5 Seam. The seam (No. 6) is thinner, the quality of the coal as mined is substantially inferior, and there is a lack of uniformity of coal occurrence. The stripping ratio (cubic yards of overburden to one ton of merchantable coal) is much greater than in the case of No. 5 Seam.

Presently there are two strip mines working in the No. 2 Seam in Fulton County. One was developed in 1958 and the other in 1962. The one mine is located on the Illinois River and utilizes barge transport exclusively. The other is located sufficiently close to the River to take advantage of barge transport. This lower cost transportation tends to offset the higher production cost of the No. 2 Seam coal. The thickness of the No. 2 Seam is approximately one-half that of the No. 5 Seam.

The Illinois Geological Survey has made estimates of the quantities of coal that occur at various depths below the surface. These estimates have no relationship to the profitability or lack of profitability of strip mining, Likewise, the estimates do not reflect the availability of surface. There are large areas that lie within the corporate limits of towns and cities. Accordingly, those estimates do not demonstrate and were not intended to demonstrate the availability of strippable reserves that can be mined profitably.

The ceiling on the price obtainable for coal for steam raising purposes is now being established by nuclear fuel. In addition, there has been tremendous progress in recent years in the development of larger and larger excavating equipment for removing the overburden from the coal seam. The effect of this has been to permit the removal of as much as 125 feet of overburden thickness from the former limit of 55 to 60 feet. A special problem arises when the overburden thickness exceeds 125 feet. This problem concerns the stability of the spoil bank which renders improbable any future technological progress in this regard. The effect of these two factors is to limit the amount of stripping of the No. 2 and No. 6 Seams that can be profitably accomplished and, in our opinion, reserves in these seams of any consequence that can be mined profitably are already controlled by operating companies.

PAUL WEIR COMPANY

Mr. Frank Nugent

July 12, 1967
- 3 -

The status of available strip coal reserves in other parts of the State of Illinois is similar to that in the four-county field. This is particularly the case in the so-called Belleville area (Jackson, Perry, Randolph and St.Clair Counties). These reserves are almost completely controlled by four operating companies, United Electric and three competitors. The one virgin area of substantial size is owned by a fifth operating company. The same situation prevails in Williamson and Saline Counties. Control is in the hands of three operating companies.

Returning to your specific question, in our opinion there are not available for purchase from non-operating owners a sufficient number of adjoining tracts that when assembled would amount to strippable coal reserves over 10 million tons.

Sincerely yours,

Paul Weir

PW:vlw

Source Material Employed in Preparation of Report by Paul Weir Company

A. Analysis of Strip-Mining Potential of the Seven Specific Coal Fields Itemized on Page 1

1. Engineering data supplied by United Electric for each field

   a. Property and/or drill maps.

   b. Logs of representative drill holes.

   c. Analyses of drill-hole cores.

2. Background and Perspective

   a. Cady, Gilbert H., Analyses of Illinois Coals. Supplement to Bulletin 62, Illinois State Geological Survey, 1948.

   b. Smith, William H., Strippable Coal Reserves of Illinois: Part 3 - Madison, Macoupin, Jersey, Greene, Scott, Morgan and Cass Counties. Circular 311, Illinois State Geological Survey, 1961.

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JOHN E. ORGAN
GEOLOGIST
SHERMAN BLDG.
SULLIVAN, INDIANA

DEFENDANT'S EXHIBIT 88

Availability of Economically Mineable
Strip Reserves within the State of Illinois

Report by John E. Organ, Geologist

In 1928, the writer obtained a Bachelor's degree in geology from Indiana University and a master degree the following year from George Washington University. An additional year of graduate work toward a Doctor's degree in geology was also spent at George Washington University. During both this period of formal education and immediately afterward, the writer found employment with an oil company and then with an operator of a strip mine in Sullivan County, Indiana.

Continuously since 1932, except for the war years, my principal occupation has been the exploration or acquisition for others of coal lands and mining rights. During this time, I have been responsible, directly or indirectly, for the exploitation of coal fields in the Midwest totaling hundreds of millions of tons. Mines subsequently developed from these properties include the Minnehaha mine of Ayrshire Collieries, the Buckheart Mine of The United Electric Coal Companies, the Sunspot Mine of Ayrshire Collieries in Clinton, Indiana, the Panther Mine of Green Coal Company in west Kentucky, the Shasta Mine of Binkley Coal Company, predecessor to Truax-Traer Coal Company, near Bicknell, Indiana, and the Sunspot (Illinois) Mine of Ayrshire Collieries. While these properties and others all involved strip coal, I have also been involved in the exploration or acquisition for others of deep coal within the States of Indiana and Illinois. In addition, I was instrumental in the acquisition of coal rights to approximately 750 million tons of strip coal in Wyoming and another 100 million tons in Montana.

JOHN E. ORGAN
GEOLOGIST
SHERMAN BLDG.
SULLIVAN, INDIANA

At present, I am on retainer to Ayrshire Collieries Corporation as a consultant.

At one time or another, I would estimate that I have made on-site investigations in virtually every coal producing county in the States of Illinois, Indiana and west Kentucky. I have made it my business to keep informed and abreast of developments in midwestern coal mining and attitudes and opinions of midwestern coal producers. I have also made frequent use of data periodically made available by The Illinois State Geological Survey and its counterpart in Indiana and Kentucky.

Based upon my knowledge and experience, I concluded that, by 1960, there was no longer any possibility of acquiring or establishing, for transfer to coal producers, of any new economically mineable strip coal acreage in the Illinois basin of sufficient size to justify the opening of new mines. Therefore, my subsequent activity was confined to investigation of deep coal properties in the Midwest and strip coal properties in the South and West. Within the past two years, I have, on numerous occasions, discussed the availability of strip reserves in the Midwest with a variety of coal executives knowledgeable in this field. I have also re-reviewed data released by the Illinois Geological Survey pertaining to this question. In my opinion, there remains no doubt that such economically mineable strip reserves as exist within the Illinois basin are under the control of existing producers, and that such other strip reserve acreage that has not been acquired holds no competitive promise. My own personal business decisions have, since 1960, been bottomed on this premise.

John E. Organ
Geologist

IMPACT OF SULFUR OXIDE REGULATIONS ON MIDWEST COAL MARKETS

Prepared for

Kirkland, Ellis, Hodson, Chaffetz and Masters
Prudential Plaza
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PART I - SULFUR OXIDE REGULATIONS

The effects of sulfur dioxide on human health are related to irritation of the respiratory tract. Whether these effects are acute or chronic, reversible or irreversible, depends on the length and intensity of exposure. Damage to vegetation and materials and reduced visibility also result from sulfur dioxide concentrations.

Adverse effects of sulfur dioxide on a receptor can occur from exposure to very high concentrations for short periods, such as a few minutes, or from relatively low concentrations over extended periods of time such as several months or years. Estimates of acceptable air quality for very short averaging periods are of necessity predicated on laboratory and clinical observations. For somewhat longer averaging times criteria are based on epidemiologic studies which analyze the effect of sulfur dioxide on groups of people living in a community. On the basis of intensive review of these scientific studies on the effects of time-concentration exposures to sulfur dioxide, the Department of Health, Education, and Welfare has reached the following conclusions regarding desirable air quality objectives:

> 0.1 parts per million (ppm) on a 24-hour average should not be exceeded more than one day in any 100 consecutive day period.
>
> 0.25 ppm should not be exceeded for more than one hour in any four consecutive day period.

0.5 ppm should not be exceeded for more than five minutes in any eight hour period.

The atmosphere in a polluted community usually contains a mixture of contaminants which collectively may have even greater deleterious effects on human health. Particulate matter emitted into the atmosphere is as much a health problem as is sulfur dioxide. Certain particles which are porous and have large surface areas trap sulfur dioxide gases within their pores and on their surface. These particles carry sulfur dioxide into the lungs where normally the gas would be unable to remain as an unattached molecule.

The Department of Health, Education, and Welfare has recently published two air quality criteria documents on particulates and oxides of sulfur. The fact that both were published at the same time indicated their combined importance and synergistic effects.

A. FEDERAL EMPHASIS ON REGULATION OF SULFUR OXIDES

From 1955 to 1965, the U. S. Department of Health, Education, and Welfare conducted several investigations of the extent of community air pollution problems throughout the country. In the midwest, extensive studies were carried out in Louisville, Kentucky, Nashville, Tennessee, and St. Louis, Missouri. Both particulate matter and sulfur dioxide levels were investigated.

As a result of these and other investigations, the Department, by 1964, began to stress the importance of sulfur oxides to the

nation's total air pollution problem.

At that time there were competing applications before the Federal Power Commission to increase the natural gas supply to Los Angeles. The most controversial issue in the case was the effect of the natural gas supply on the Los Angeles air pollution problem. It was contended by air pollution control officials and others that exclusive seasonal use of this virtually sulfur-free fuel was necessary to the health and welfare of the people of Los Angeles. The El Paso Natural Gas Company and Transwestern Pipeline Company proposed increased deliveries on an interruptible basis. Gulf Pacific proposed a less flexible 20-year fixed fuel supply. The latter was supported by the Los Angeles County Air Pollution Control District and the California Public Utilities Commission whose position was reinforced by the expert testimony of Vernon G. MacKenzie, then Assistant Surgeon General of the Public Health Service and Chief of the Federal Division of Air Pollution. Mr. MacKenzie testified that sulfur dioxide "concentrations of 10 parts per hundred million (0.1 ppm on a 24-hour average) correspond to about the lowest average concentration which has been associated with undesirable effects on humans" and that this concentration should not be exceeded more than one percent of the time. However, he maintained that there is no evidence to substantiate categorically that even this is a safe level.

Sulfur dioxide emissions became an issue at the Federal Power Commission again in 1967 when the Department supported efforts to increase the supply of natural gas to Consolidated Edison in New York. It contended that Con Ed's generating plants contributed significantly to Metropolitan New York's sulfur dioxide levels, which exceeded the 0.1 ppm criterion, and that increased use of natural gas by Con Ed would contribute to the 83 percent reduction in concentrations necessary to meet it. In this case the Commission acted favorably on the application of the supplier.

During this hearing the Department backstopped its contentions on the fuel needs of the private sector of Metropolitan New York by pointing to the stringency of the sulfur-in-fuel restrictions imposed on Federal facilities in that area which are based on the 0.1 ppm criterion.

These regulations which also apply to the Chicago and Philadelphia metropolitan areas, were promulgated by the Secretary of Health, Education, and Welfare pursuant to Executive Order No. 11282 of May 26, 1966. The order directs all Federal agencies to take steps to prevent and control air pollution from their installations.

Though the regulations take the form of emission limitations they are, in effect, sulfur-in-fuel regulations because, as the National Air Pollution Control Administration recently advised one Federal agency, current research on developing control techniques

for reducing sulfur oxides from stack gas is directed toward methodology for power-generation sources and not toward combustion units as small as those utilized in these facilities. The regulations specify that emissions shall not exceed 0.35 lbs. of SO_x per 10^6 BTU in New York City or 0.65 in Chicago and Philadelphia. The equivalent sulfur content of fuels thus required are 0.2 percent for coal and 0.3 percent for oil in the New York area and 0.45 percent and 0.6 percent respectively in Chicago and Philadelphia. (The Metropolitan Chicago counties covered by the regulations are McHenry, Kane, Lake, Cook, Dupage, and Will in Illinois, and Lake and Porter in Indiana.)

Federal facilities located outside of the three specified areas must conform to state and local air pollution regulations of the areas in which they are located or, in the absence of such regulations, must burn the lowest sulfur content fuel that is reasonably available. In determining reasonable availability, the factors to be considered include price, firmness of supply, extent of existing pollution, and assurance of supply under adverse weather and natural disaster conditions.

Another vehicle which the Department has employed since 1966 to promote the adoption of standards conforming to its recommended air quality objectives is an abatement action. The Clean Air Act authorizes the Secretary of Health, Education, and Welfare to initiate abatement procedures in interstate pollution situations and

empowers him to act when requested to do so by a state in either interstate or intrastate air pollution problems. Nine interstate and one intrastate abatement actions instituted to date include:

Selbyville, Delaware - Bishop, Maryland
Ticonderoga, New York - Shoreham, Vermont
New York - New Jersey Metropolitan Area
Kansas City, Kansas - Kansas City, Missouri
Lewiston, Idaho - Clarkston, Washington
Washington, D.C. Metropolitan Area
Parkersburg, West Virginia - Marietta, Ohio
Ironton, Ohio - Ashland, Kentucky - Huntington, West Virginia
Knox Township, Ohio - New Cumberland, West Virginia

Garrison, Montana (intrastate)

The relative stringency of sulfur-in-fuel limitations required to alleviate varying levels of existing pollution can be illustrated by considering only two of the abatement actions. In the New York - New Jersey Metropolitan Area, which has the highest ambient air levels of sulfur dioxide in the Nation, the abatement conference participants recommended the 0.1 ppm for a peak 24-hour average concentration and stringent sulfur-in-fuel regulations identical to those governing Federal facilities in that area--i.e., 0.2 percent for coal and 0.3 percent for oil. In the Parkersburg, West Virginia - Marietta, Ohio, abatement action, on the other hand, the conference participants recommended the same ambient air standard, but recommended less stringent sulfur limitations--2.0 percent on fuels burned by all existing power or steam generating plants after October 1, 1968, and 1.5 percent for all new or expanded power or steam generating plants. This, of course, reflects the fact that the sulfur dioxide levels in the Parkersburg-

Marietta area were not as high as those of New York City and the same stringency of regulation would not be required to achieve similar ambient air quality. (The Secretary of Health, Education, and Welfare has not as yet issued formal recommendations for Parkersburg-Marietta.)

In January of 1969 the Department published the first criteria documents on sulfur dioxide and particulate matter. The criteria will serve as a basis for air quality and emission standards which the states will be required to set applicable to air quality control regions. The final conclusions of the sulfur dioxide criteria document state that adverse health effects were observed when 24-hour average levels of sulfur dioxide exceeded 0.11 ppm for three to four days and advised that in promulgating air quality standards consideration should be given to margins of safety--another reference, if indirect, to the recommended 0.1 ppm for a peak 24-hour average concentration.

B. STATE AND LOCAL REGULATIONS IN THE MIDWEST

The Air Quality Act places primary responsibility for the prevention and control of air pollution at its source on state and local governments and encourages cooperative activities between them leading to uniform laws. It also encourages similar cooperation between states. However, air quality control regions shall be designated by the Secretary when in his judgement protection of public health and welfare requires establishing air quality standards.

As of June 15, 1969, 13 regions had been designated and five proposed out of a total of 57 areas throughout the country which have been identified for inclusion. Regions to be established in the vicinity of the midwest coal fields include:

Minneapolis-St. Paul, Minnesota
Milwaukee, Wisconsin
Detroit, Michigan
St. Louis, Missouri
Chicago, Illinois
Indianapolis, Indiana
Dayton, Ohio
Cincinnati, Ohio
Toledo, Ohio
Louisville, Kentucky
Memphis, Tennessee

Many states and localities have commonly regulated particulate emissions. In recent years more than half of the new particulate emission ordinances have been more restrictive than one pound per million BTU hourly input, and the trend is to limits less than 0.5

pounds. The New York City requirement for 99% efficiency of particulate control equipment on bituminous coal burning units and the recent New Jersey State proposal to require the same efficiency level of all dust collection control equipment recognize the improved particulate control technology of today. The cost of highly efficient particulate control equipment is, of course, an economic factor for coal burning operations, particularly when coal of high ash content and low volatility is utilized.

Any existing sulfur oxide standards in the eleven areas listed earlier, as well as in others who act voluntarily, are subject to change and new ones will soon be promulgated. Conclusions of the document "Air Quality Criteria For Sulfur Oxides" and the stringent air quality objectives consistently recommended by the Department in the past strongly suggest that the Secretary will approve air quality and emission standards of state agencies only if they are consistent with the Department's guidelines.

Table 1 outlines the existing and locally proposed air quality standards for sulfur dioxide in the area of the midwest coal fields. These standards prescribe the exposure to this pollutant which a political jurisdiction determines should not be exceeded in a specified geographic area, and are used as one of several factors in designing legally enforceable pollutant emission standards. The table illustrates the trend to adoption of 0.1 ppm for a maximum 24-hour

TABLE 1

AIR QUALITY STANDARDS FOR SULFUR DIOXIDE IN THE AREA OF THE MIDWEST COAL FIELDS

AREA	CONCENTRATION	AVERAGING TIME - FREQUENCY
Minneapolis-St. Paul Metropolitan Area	0.02	maximum annual average
	0.10 ppm	24-hr. average not to be exceeded over 1-day in any 3-month period.
St. Louis Metropolitan Area *	0.02 ppm	maximum annual average (24-hr. sampling time)
	0.10 ppm	24-hr. average not to be exceeded over 1-day in any 3-month period.
Chicago Metropolitan Area ** (proposed - subject to public hearing)		<u>Interim Goal to be Met by 1-1-72</u>
	0.03 ppm	maximum annual average (24-hr. sampling time)
	0.15 ppm	24-hr. average not to be exceeded more than 1% of the time.
	0.25 ppm	24-hr. maximum
		<u>Standard to be Met by 1-1-74</u>
	0.015	maximum annual average (24-hr. sampling time)
	0.10	24-hr. average not to be exceeded more than 1% of the time.
	0.20	24-hr. maximum
	0.5	1-hr. maximum

*City of St. Louis and St. Charles, St. Louis, and Jofferson Counties
**McHenry, Kane, Lake, Cook, Dupage, and Will Counties

TABLE 1 - CONTINUED

AIR QUALITY STANDARDS FOR SULFUR DIOXIDE IN THE AREA OF THE MIDWEST COAL FIELDS

AREA	CONCENTRATION	AVERAGING TIME - FREQUENCY
Illinois Portion of St. Louis Metropolitan Area* (proposed-subject to public hearing)	Both 1972 interim goals and 1974 Standards are the same as for Chicago Metropolitan Area.	
East Chicago, Indiana	No person shall cause, let, permit, suffer or allow any emission of sulfur oxides which results in ground level concentration of sulfur oxides at any given point in excess of 0.5 ppm (volume) in the period of any hour and average exposure shall not exceed 0.1 ppm (volume) of sulfur oxide in any 24-hour period. These limitatins shall not apply to ground level concentration occurring on the property from which such emission occurs, provided such property, from the emission point to the point of any such concentration is controlled by the person responsible for such emission.	
Gary, Indiana	Same as East Chicago	
Hammond, Indiana	Same as East Chicago	
Cincinnati (proposed)	0.2 ppm	1-hr. average not to be exceeded more than 1 time in any 7-day period.
	0.10 ppm	24-hr. average not to be exceeded more than 4-days in any calendar year.
	0.02 ppm	maximum annual average

*Madison, St. Clair, and Monroe Counties

TABLE 1 - CONTINUED

AIR QUALITY STANDARDS FOR SULFUR DIOXIDE IN THE AREA OF THE MIDWEST COAL FIELDS

AREA	CONCENTRATION		AVERAGING TIME - FREQUENCY
Kentucky State (proposed)	I, II, III, Rural, Residential, Commercial	IV Industrial	
	.04 ppm	.06 ppm	one year
	.09 ppm	.04 ppm	one month
	.18 ppm	.27 ppm	one day (24-hr) 99% (once in 3 mos)
	.32 ppm	.48 ppm	two hours 99% (once in 8 days)
	.38 ppm	.57 ppm	one hour 99% (once in 4 days)
Nashville-Davidson County, Tennessee	0.02 ppm		maximum annual average (24-hr. sampling time)
	0.10 ppm		24-hr average not to be exceeded over 1-day in any consecutive 100 day period.
Memphis, Tennessee (also proposed for Shelby County)	No person shall cause, allow, or permit any emissions of sulfur oxides which results in ground level concentrations at any point in excess of 0.5 ppm by volume for a continuous period of more than 1-hr., and the average concentration shall not exceed 0.10 ppm by volume of sulfur oxides in any 24-hr. period.		

average sulfur dioxide concentration. This standard is already in effect in St. Louis, East Chicago, Gary, Hammond, Nashville-Davidson County, and Memphis, and is proposed for Minneapolis-St. Paul, Cincinnati, and Shelby County, Tennessee.

The Illinois State proposal for its portions of the Chicago and St. Louis air quality control regions is for a 0.20 ppm maximum 24-hour average, but since the proposed standards would permit the 24-hour average to exceed 0.10 ppm only 1 percent of the time, it is essentially the same as the others. Thus, the Kentucky State proposal of 0.18 ppm for rural, residential, and commercial areas and 0.27 ppm for industrial areas is the only exception. The proposed Illinois standards are to be met by 1974, but as outlined in Table 1, it is also proposing interim goals to be met by 1972. Both the standards and goals are subject to public hearing in Chicago on August 5 and Edwardsville on August 12. The standards adopted for these two areas of Illinois could be applied statewide.

Table 2 lists current emission standards and sulfur-in-fuel regulations in the area of the midwest coal fields. Emission standards are enforceable limitations, usually based on ground-level concentrations, on the amount of a pollutant which may be emitted from any source. Sulfur-in-fuel regulations prescribe the sulfur content of fuels which may be transported into, sold, or burned in a given jurisdiction. Most recent regulations for control of sulfur oxides emissions are based on the latter. These generally correlate

TABLE 2

EMISSION STANDARDS AND SULFUR-IN-FUEL REGULATIONS IN THE AREA OF THE MIDWEST COAL FIELDS

LOCALITY	MAXIMUM ALLOWABLE SULFUR CONTENT (BY WEIGHT)	EFFECTIVE DATE
Minneapolis-St. Paul (proposed) (Less than 2,000 million BTU per hour capacity)	2.0%	Effective date of the Act (during air pollution alerts.)
(2,000 million or more BTU per hour capacity)	2.0%	Effective date of the Act (during air pollution alerts.)
	1.5%* (Coal) 2.2%* (Oil)	April 1, 1972 (during air pollution alerts.)
Cedar Rapids, Iowa (heat input of less than 1 million BTU per hour)	The lowest sulfur content fuel that is reasonably available.	November 5, 1968
St. Louis (Less than 2,000 million BTU per hour capacity)	2.0%	October 1, 1969 (applicable Oct.-March thereafter)
(2,000 million BTU per hour capacity or more)	No higher average sulfur content than the fuel or fuels used from 3-24-66 to 3-24-67	March 24, 1967
	2.2% (Oil)	March 24, 1970
	1.5% (Coal	March 24, 1970
Chicago	2.5%	July 1, 1970
	2.0%	July 1, 1971
	1.5%	January 1, 1973
Chicago (Federal Facilities)	0.6%* (Oil)	October 1, 1969
	0.45%* (Coal)	October 1, 1969
Cincinnati (Less than 200 million BTU per hour input	1.25%** on a day basis (averaged over a period of not less than one month nor more than one year	January 22, 1969
(more than 200 million BTU per hour input	new installations require policy decision of Air Pollution Board	Same
Nashville-Davidson County, Tennessee	2.0%	March 1, 1970

* Emission Standard

** Is deemed to comply with emission restrictions

To convert pounds of SO_2 emissions per million BTU to percentage of sulfur in fuel, place a straight-edge at appropriate number in right-hand column. Going from right-hand column to center column run straight-edge through number corresponding to the heat value of the fuel. Straight-edge then points to proper percentage figure in left-hand column. To convert percentage of sulfur in fuel to pounds of SO_2 emissions, reverse the procedure.

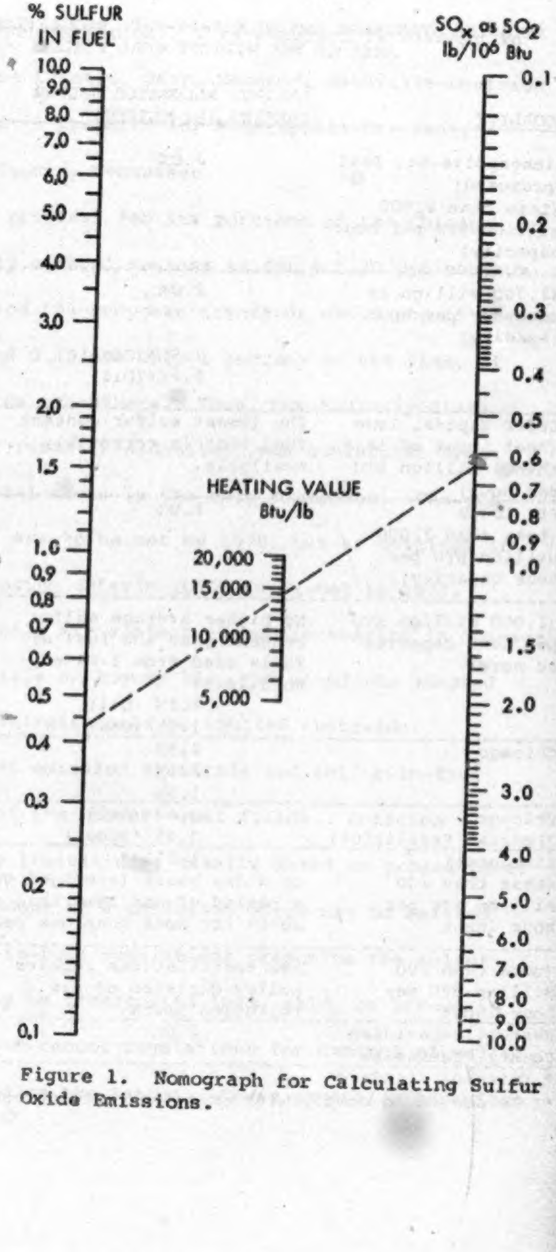


Figure 1. Nomograph for Calculating Sulfur Oxide Emissions.

evaluations of current air quality with the reduction in emissions of these pollutants necessary to obtain desirable air quality and represent calculations of the maximum sulfur content fuel which will produce emissions consistent with the required reduction. The choice of fuel within these limitations is then the province of fuel producers fuel suppliers, and fuel users. Some regulations which prescribe the sulfur content of fuels provide a discretionary clause as to fuel use so long as sulfur dioxide emissions do not exceed prescribed limits. This leaves the fuel user free to exercise other options of control if and when they are available. (In some cases the figures in Table 2 were calculated from the "Nomograph for Sulfur Oxide Emissions" (Figure 1).)

Without exception, the state air pollution control agencies of Minnesota, Wisconsin, Michigan, Iowa, Missouri, Illinois, Indiana, Ohio, Kentucky, and Tennessee report varying stages of activity in developing new sulfur dioxide standards or revising old ones at the state or local level, or both.

The Chicago City Council, last month, postponed the effective date of the first step in its three-stage sulfur-in-fuel regulation from July 1, 1969, to July 1, 1970. This step limits the sulfur content to 2.5 percent. The effective dates of the other two stages--

2.0 percent on July 1, 1971, and 1.5 percent after January 1, 1973--were not altered by this change (Table 2).

In 1968 the Missouri Air Conservation Commission agreed to postpone the effective date of the sulfur-in-fuel regulation for the non-utility market in St. Louis from that year to 1970 on the condition that Peabody Coal Company drop a suit challenging the legality of the regulations and undertake to open a low-sulfur coal mine to supply the non-utility St. Louis market. However, when Peabody announced early in June, 1969, that it was abandoning plans to open the mine, the effective date immediately was advanced from 1970 to the 1969 heating season.

The other sulfur-in-fuel regulations for smaller combustion units outlined in Table 2 show limitations ranging from 0.6 percent for oil and 0.45 percent for coal for Federal facilities in Chicago, to 1.25 percent in Cincinnati, and 2.0 percent in Minneapolis-St. Paul and Nashville-Davidson County. Cedar Rapids requires the use of fuel with the lowest sulfur content that is reasonably available.

Cincinnati's regulation is actually an emission limitation but stipulates that the use of fuels containing less than 1.25 percent sulfur on a dry basis, averaged over a period of not less than one month nor more than one year, is deemed to comply with the emission limitation. The regulations restrict the concentration of sulfur dioxide from exhaust gas to that concentration resulting

from the burning of the fuel having an average sulfur content no higher than that used collectively in combustion equipment of less than 200 million BTU per hour input rating in the City during the 24-months prior to January 22, 1969.

The proposed Minneapolis-St. Paul restrictions, contained in Minnesota State regulations currently under consideration, would apply only during air pollution alerts. Such alerts would be declared at any time the 24-hour average concentration of sulfur dioxide in the ambient air exceeds the value of 0.1 ppm, and conversion to low sulfur fuel, a supply of which users will be expected to have on hand, will be required. The St. Louis regulations and those proposed for Minneapolis-St. Paul for combustion installations with a capacity of 2,000 million BTU per hour or more are emission standards and limit the emission of sulfur dioxide to 2.3 pounds per million BTU of heat input. In the absence of control equipment with the efficiency to prevent emissions over this level, fuel oil with a maximum sulfur content of 2.2 percent or coal with no more than 1.5 percent sulfur would have to be utilized. New installations of more than 200 million BTU per hour input in Cincinnati will require a policy decision of the Air Pollution Board. (There are presently no boiler units in the City of Cincinnati fired by coal or oil having an hourly heat input of more than 200 million BTU and none projected. All larger units burn natural gas.)

It is recognized that legislative bodies often pattern laws and

regulations after those of other jurisdictions. Dade County, Florida, for instance, adopted as its own several sections of the Los Angeles County ordinance and Minneapolis was earlier proposing an ordinance very similar to that of St. Louis. Furthermore, state agencies, when faced with a similar problem in several of its communities, may promulgate rules and regulations on a regional or even statewide basis. However, projections for midwest cities or metropolitan areas which have not as yet enacted sulfur-in-fuel regulations can best be made on the basis of available information on the extent of their sulfur dioxide problem.

The 1966 density of sulfur dioxide emissions for several midwest metropolitan areas has been calculated by the National Air Pollution Control Administration. Figure 2 illustrates the rate of emissions in tons per square mile per year. The Chicago-Gary, Indianapolis, Toledo, and Louisville-New Albany metropolitan areas had SO_2 emissions in excess of 200 tons/mi^2/yr. Detroit, St. Louis-East St. Louis, and Cincinnati-Covington had emission densities ranging from 100 to 200 tons/mi^2/yr. Other cities had less than 100 tons per square mile per year or were not surveyed.

Levels of sulfur dioxide measured in the ambient air in eleven of these communities has been tabulated by the National Air Pollution Control Administration (Table 3). Results are based on National Air Sampling Network impinger samples collected at one location for 24-hours approximately once every two weeks. Results

TABLE 3

Summary of 1967 Sulfur Dioxide Levels
in Major Midwest Metropolitan Areas.

METROPOLITAN AREA	NUMBER OF SAMPLES	PARTS PER MILLION *		
		MIN.	MAX.	ARITH. MEAN
Chicago, Illinois (CAMP)	24	0.004	0.254	0.089
Cincinnati, Ohio (CAMP)	24	0.006	0.050	0.016
Covington, Kentucky	26	0.001	0.029	0.012
Dayton, Ohio	25	0.001	0.042	0.008
Des Moines, Iowa	26	0.002	0.026	0.006
East Chicago, Indiana	24	0.008	0.160	0.045
Indianapolis, Indiana	23	0.003	0.062	0.020
Milwaukee, Wisconsin	24	0.005	0.038	0.016
Minneapolis, Minnesota	25	0.003	0.111	0.019
Nashville, Tennessee	24	0.002	0.029	0.009
St. Louis, Missouri (CAMP)	48	0.007	0.113	0.034

*All values are based on 24-hour averaging time.

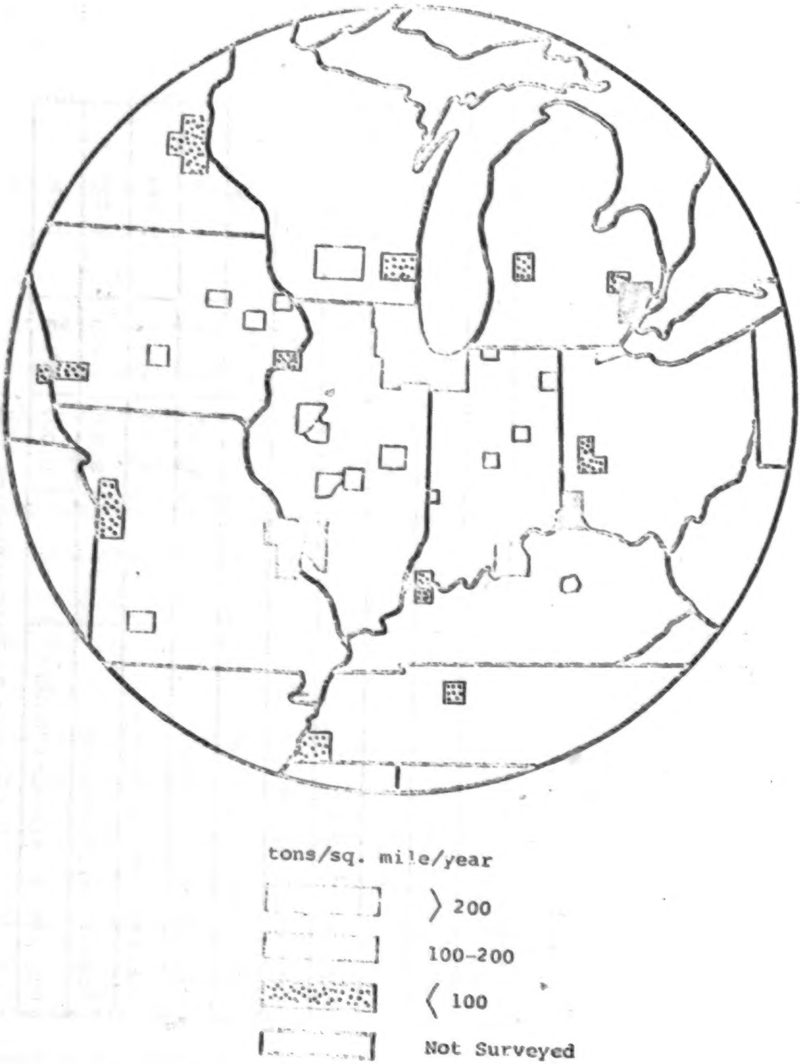


Figure 2. Estimated 1966 Emissions of Sulfur Dioxide in Major Midwest Metropolitan Areas.

are relevant to this report primarily to show relative pollution levels but are not adequate to define the magnitude or severity of a community's sulfur pollution problem.

Chicago showed the highest concentration of sulfur dioxide--some ten times that of Des Moines, Dayton, and Nashville which had the lowest levels. Intermediate concentrations, in descending order, were found in East Chicago, St. Louis, Indianapolis, Minneapolis, Milwaukee, Cincinnati, and Covington.

Within the next year or so regulations can be anticipated for air quality control regions in Milwaukee, Detroit, Indianapolis, Dayton, Toledo, Louisville, and Memphis. The emission density data and the air quality data do reflect expected similarities for communities in the entire region. For these metropolitan areas, sulfur-in-fuel limits in the range of 2.0 percent or less (or equivalent stack emission standard) can be anticipated.

For communities such as Des Moines, Davenport, Dayton, and Nashville, and other industrial centers of similar size, measured sulfur dioxide pollution levels and emission density suggest that sulfur-in-fuel limits slightly greater than 2.0 percent would suffice to provide desirable air quality. In these communities, regulations may well be promulgated to prevent gradual degradation of the existing air quality rather than allow pollution emissions to continue to increase until the standards are on the brink of being exceeded. Regulations may also be promulgated by these

smaller communities, without serious existing pollution problems, to prevent dumping of high-sulfur fuels which are banned in other areas. Also, as pointed out earlier, the State agencies may promulgate statewide regulations.

While some communities may use emission standards, a more direct approach is to limit the sulfur content of all fossil fuels to a maximum percent after a specified date. This approach is easier to enforce than emission limitations which would require expensive stack testing. Even Los Angeles with three highly qualified and experienced source test teams chose to limit the sulfur contents of combustion fuels rather than be obligated to undertake a very expensive, time consuming, and perennially controversial methodology of testing which could not be equitably and effectively implemented. Los Angeles County as early as 1958 adopted stringent sulfur-in-fuel regulations which have twice been strengthened, and which now limit sulfur content of fuel oil to 0.5 percent any time of the year.

In light of existing fuel regulations in the midwest and projections of regulations to come, the burning of coal having a sulfur content higher than 3.0 percent will be severely curtailed, if not altogether eliminated, in non-utility markets within the next ten years. Moreover, the regulatory trend, such as the existing St. Louis standards and those proposed for Minneapolis-

St. Paul requiring combustion installations with a capacity of 2,000 million BTU per hour or more to utilize 1.5 percent coal or employ efficient control equipment not yet commercially available, the proclivity of communities to pattern regulations after those of other communities, and forthcoming public consideration of new or revised regulations required for air quality control regions raise the possibility that the use of coal with a sulfur content in excess of 3.0 percent will also be severely curtailed in utility operations.

PART II - CONTROL OF SULFUR OXIDE EMISSIONS

Emphasis on sulfur oxides control technology research and development began with the Clean Air Act of 1963, continued with additional specific directions to the Secretary of Health, Education, and Welfare in an amendment in 1965, and was restated in the Air Quality Act of 1967. The latter Act requires the Secretary to "give special emphasis to research and development into new and improved methods, having industry-wide application, for the prevention and control of air pollution resulting from the combustion of fuels." The research is to be directed toward development of improved, low-cost techniques for the control of combustion byproducts and for removal of potential pollutants from fuel. Federal expenditures for these purposes have now reached a level of about $15 million a year. There are three main approaches presently being explored for reducing sulfur oxide emissions: substitution of low sulfur fuels, coal desulfurization, and flue gas desulfurization. Each of these approaches and the status of current projects are described in this part of the report.

A. SUBSTITUTION OF LOW SULFUR FUELS

One of the more obvious measures to reduce emissions of sulfur oxides is to use low sulfur fuels. Coal, oil, and natural gas exist with naturally-occurring sulfur contents low enough to satisfy sulfur oxide emission regulations, but the supplies of these fuels are limited--in the case of coal extremely so--and their availability and cost vary with geographic location.

Technology exists for reducing the sulfur content of oil and it is employed by refiners for removing greater and greater percentages of the sulfur in oil before refined products are sold. Natural gas contains virtually no sulfur and can meet any projected sulfur oxide limitation without alteration of its characteristics.

Essentially all of the residual fuel oil used in the midwest is produced in domestic refineries. Total production of this product in 1968 in PAD District II (North Central United States) was 56 million barrels. The sulfur content averaged about 1.75 percent. Thirty-three Federal facilities in the midwest reported using residual fuel oil in 1967 ranging in sulfur content from 0.4 to 8.0 percent with a median of 1.5 percent. Utilities also use residual oil but to a lesser degree. It is used by Union Electric at its Cahokia station in four of the six boilers. In 1968, 265,950 barrels were burned; this fuel had a sulfur content of 2.3 percent and the cost was $2.80 per barrel delivered (44 cents per million BTU).

Imported residual fuel oil could be put on barges at the Gulf Coast and moved to several large cities on the Mississippi River (Memphis, St. Louis, Davenport, and Minneapolis-St. Paul) or Ohio River (Louisville and Cincinnati) or other tributaries. According to a spokesman for a major oil company at the Industrial Fuels Conference held in St. Louis in February 1969, the price at the Gulf Coast is about $1.75 and allowing 60 cents per barrel for barge transportation, this fuel could be sold for $2.35 per barrel in the midwest (39 cents per million BTU). In 1968, barge movements of domestic resid via the Mississippi River from District III (Gulf States) to District II amounted to only about six million barrels. So long as new sulfur requirements are not extremely stringent (less than 1%) refiners can be expected to continue producing some residual fuel oil in domestic refineries using either domestic or foreign crude.

The Federal Power Commission has repeatedly granted authorization for increased natural gas deliveries to the midwest. The authorized supply and ready availability of natural gas to meet it have reduced coal usage in the domestic, commercial, and industrial fuel markets in the past and can be expected to infringe to some extent on the utility coal markets in the future. As an example, at the Commonwealth Edison plants in Chicago, natural gas is burned under boilers during the non-heating season for 22 to 30 cents per million BTU. The company has indicated its intention

of increasing gas consumption at its older plants located in or near the City of Chicago to help alleviate the sulfur oxide pollution problem.

A Federal Power Commission decision earlier this year allowed an additional 50 million cubic feet daily of natural gas--equivalent to 750,000 tons of coal annually--to be imported into the St. Louis market for non-utility use. This development was cited by the Peabody Coal Company as a factor in its decision to abandon the plan to open a low sulfur coal mine at Troy, Illinois, to serve the St. Louis retail market. Economics and mineability of the coal were other factors. Average values of natural gas for commercial and industrial uses consumed in the area of the midwest coal fields in 1967 are shown in Table 4.

Naturally-occurring low sulfur coal in the midwest field, (coal which can be mined and cleaned to 2.5% or lower sulfur content), reportedly is very scarce. Moreover, in existing electric utility coal-fired boilers technical and economic problems are sometimes associated with substituting low sulfur coal for the coal presently being burned. In switching from high to low sulfur coal, heat release, ash fusion temperature, and electrostatic precipitator efficiency can be greatly affected.

A recent report of the Federal Power Commission's West Central Advisory Committee stated that coal will be faced with continuing pressures as an energy source in the area. "In view

TABLE 4

AVERAGE VALUE OF NATURAL GAS CONSUMED IN 1967
IN THE AREA OF THE MIDWEST COAL FIELDS

(cents per Mcf)

STATE	COMMERCIAL USE	INDUSTRIAL USE (Encluding field use*)
Minnesota	72.6	34.3
Wisconsin	83.6	43.9
Michigan	81.9	50.8
Iowa	65.6	29.1
Missouri	61.4	29.9
Illinois	75.9	42.1
Indiana	85.6	44.3
Ohio	74.7	52.5
Kentucky	70.7	41.3
Tennessee	71.5	32.3

* "Field use" is use of gas for steam power generation for drilling and pumping; fuel for refineries; etc.

of the probably increasing fossil fuel costs and transportation difficulties, decreasing nuclear fuel costs, and a growing concern for air pollution," the report forecasts, "by the year 1990 nuclear fuel will account for 57 percent of the region's generating capacity and nearly 70 percent of its energy requirements."

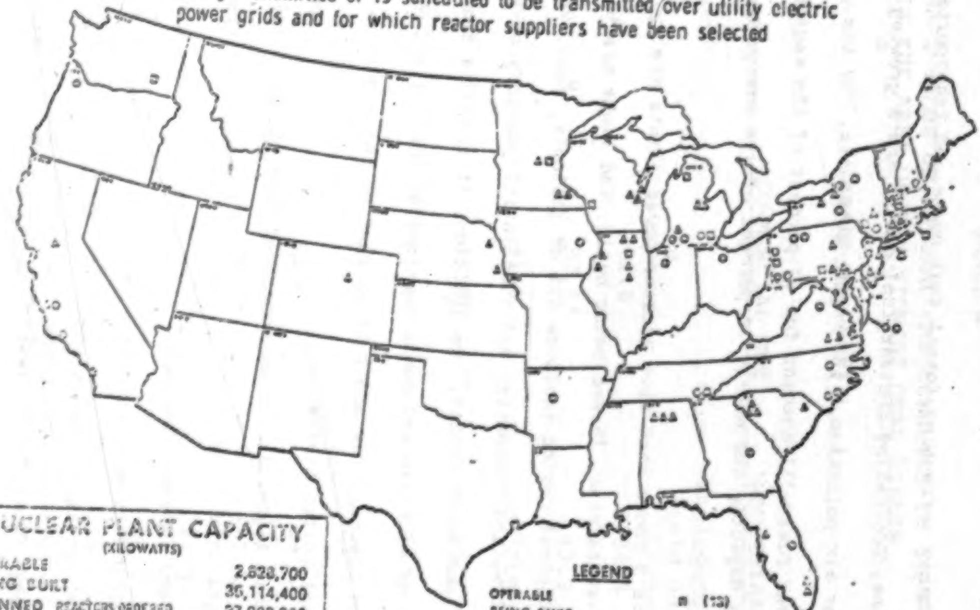
Figure 3 shows that five nuclear power plants are operable in the 10-state area, 15 are being built, and eight are planned. The West Central region includes all of Illinois, Iowa, Minnesota, North Dakota, and Wisconsin, and substantial portions of Missouri, Nebraska, and South Dakota. In addition, it includes the upper peninsula of Michigan and small portions of Montana and Wyoming. The region accounts for about 14 percent of the population of the continental United States.

In this light, it can be concluded that the availability of natural gas in the midwest, the low sulfur content of the oil produced and refined there, and the growth of nuclear energy and mine-mouth plants will encourage air pollution control officials of the midwestern states to adopt regulations prescribing the legal limits of sulfur in fuels even though coal to meet them may be unavailable.

Figure 3

NUCLEAR POWER PLANTS IN THE UNITED STATES

The nuclear power plants included in this map are ones whose power is being transmitted or is scheduled to be transmitted over utility electric power grids and for which reactor suppliers have been selected



NUCLEAR PLANT CAPACITY
(KILOWATTS)

OPERABLE		2,828,700
BEING BUILT		35,114,400
PLANNED	REACTORS ORDERED	27,902,300
	REACTORS NOT ORDERED	8,255,000
	TOTAL	74,100,400

ELECTRIC UTILITY CAPACITY BY CONVENTIONAL MEANS AS OF JANUARY 31, 1969 291,163,[illegible] KILOWATTS

LEGEND

OPERABLE	■	(13)
BEING BUILT	▲	(46)
*PLANNED (Reactors Ordered)	●	(32)

*[illegible] more plants have been announced for which reactors have not yet been ordered.

U.S. Atomic Energy Commission
March 31, 1969

B. COAL DESULFURIZATION

The concept of coal desulfurization through pyrite removal, liquefaction, or gasification is not a new one. For years pyrite removal has been practiced to upgrade the quality of certain coals, increasing their value and marketability. Commercial production of artificial illuminating gas from coal was initiated about 150 years ago. Prior to and during World War II German scientists and engineers, realizing the need for alternate petroleum supplies, researched and developed commercially applicable coal liquefaction processes for producing aviation and motor gasolines, diesel fuel, and lubricants from coal. However, these processes were costly and hazardous. Desulfurization of coal in these instances was a byproduct and not a main objective. New impetus at the Federal level was given to research and development on desulfurization of coal after recent passage of several stringent air pollution regulations designed to control sulfur levels in the atmosphere. Each of these processes, their status, timing, and costs, are considered in the ensuing discussion.

Pyrite Removal

Sulfur occurs in coal in three principal forms: sulfate, organic, and pyritic. The amount of sulfate sulfur in freshly mined coal is normally small and of little significance. Organic

sulfur found in coal is more or less uniformly distributed throughout the coal substance in molecular combination and cannot be removed even partially without materially altering the nature of the coal substance. The organic sulfur content of coal generally ranges from a low of about 20 percent to a high of about 60 percent of the total sulfur. Obviously, the organic sulfur content of a coal is the prime parameter in determining whether or not significant total sulfur reductions can be made with a given coal by pyrite removal.

Since pyrite is present as a discrete particle, theoretically it can be separated mechanically from the associated coal. In most coals, however, the pyrite particles are so small and so intimately mixed with the coal that extremely fine crushing is necessary to break them apart and permit separation. Presently, this fine crushing is obtained only at utilities having pulverizers.

Bituminous Coal Research, Inc., is presently engaged in a pilot study on in-plant removal of pyritic sulfur utilizing characteristics of the pulverizer which accepts 1 1/2 in. coal, and deliver 200-mesh coal to the burners. Initial study involves optimization of pulverizer performance, seeking a maximum reject of pyrite with a minimum loss of good coal. The process will result in the rejection of a pyrite-rich fraction, with some loss of good coal which otherwise would have been burned. Additional

research by others is directed toward the ultimate utilization of the pyrite-rich coal fraction. Successful utilization can favorably affect the economics of the pyrite removal process.

As the pyrite particle size becomes smaller, the choice of cleaning becomes more difficult and costly. Furthermore, transportation of smaller sized coal particles (below about 1 1/4 inch) may lead to other problems.

Mechanical cleaning devices are divided into two general classes, wet and pneumatic, both involving a stratification effect. Depending on the quality of the final product desired, the cost may vary from 15 to 20 cents per ton for coarse cleaning without thermal drying to more than 70 cents per ton for fine coal cleaning (includes 40 cents per ton for thermal drying).

Use of chemical methods for sulfur reduction results in pyrite sulfur removal solely. With these methods, as with mechanical methods, pyrite particles must be physically separated from the coal substance before reactions for sulfur removal can be expected to take place at reasonable rates. Chemical treatment techniques are very expensive compared with the above costs of mechanical methods and it is doubtful that such exotic methods will advance to widespread commercial application. Because of the fine grinding required to expose the pyrite particles, chemical

treatment would have to be conducted at the site of use to avoid increased transportation costs. Furthermore, water used to remove the sulfates would have to be purified prior to disposal or re-use.

Mechanical and chemical methods of cleaning, at best, result only in partial removal of pyrite sulfur, itself only a fraction of the total sulfur in the coal. In the midwestern coal fields, where total sulfur content varies from about 2.0% to 5.0% and pyrite sulfur represents only 50% of this figure, coal cleaning methods which remove only a portion of the pyritic sulfur will not often result in coal quality sufficient for compliance with present or projected air pollution fuel use regulations. For example, if a coal containing 3.0 percent sulfur, 50 percent of which is pyritic sulfur, is cleaned by some process of one-third of the pyritic sulfur, the sulfur content is reduced by 0.5 percent to 2.5 percent. Therefore, for the utility coal market where long term coal contracts are common, it is doubtful that pyritic sulfur removal in itself will allow coal suppliers to meet the midwestern low sulfur fuel demands. Generally speaking, coal preparation prior to combustion will find application only where a relatively simple and inexpensive method of cleaning will remove sufficient sulfur from a specific coal to make it an acceptable fuel under terms of a particular market restriction.

Coal Gasification and Liquefaction

Technology for producing synthetic gas from coal has long been available. However, these processes produced gases with low calorific value, ranging from 120 to 600 BTU per cubic foot as contrasted with an average of 1,035 BTU per cubic foot for natural gas.

Several coal gasification processes currently under serious consideration are in various stages of development, although none is ready for commercial application. These processes are: hydrogasification, CO_2 acceptor, molten salt, and two-stage superpressure gasification.

Since 1964, the Office of Coal Research (OCR), Department of the Interior, has allocated approximately $25 million for research in this field. The American Gas Association (AGA) and the gas industry have spent about $7 million in the past 23 years supporting coal gasification research. From present development it can be readily concluded that pipeline gas obtained from the gasification of coal (presently estimated to cost approximately 40 cents to 50 cents per million BTU compared to 18 cents to 20 cents per million BTU for natural gas) will not be commercially available even on a limited basis within the next decade.

Liquefaction is not a desulfurization process per se because the sulfur is not removed and appears in the end-products which require subsequent hydrogenation treatment.

Since 1962, the OCR has allocated approximately $26 million to research and development for commercial coal liquefaction processes. These funds sponsored four projects: H-Coal Process, Project Seacoke, Project Coed, Project Gasoline.

Manufacture of synthetic liquid fuels does not promise to be a commercial reality for the next ten to 20 years, and at present most of the research in coal liquefaction is oriented toward the production of gasoline. High sulfur char, a byproduct of the liquefaction process, can be converted to a low sulfur substance with a potential to be used as a clean fuel. However, it is presently used only to generate enough power for the liquefaction process and has not been sought as a commercial fuel.

C. FLUE GAS DESULFURIZATION

First-generation flue gas processing methods which are approaching the stage where technical, engineering, and economic feasibility might be established for commercial application on large power plants include: (1) limestone injection, (2) Combustion Engineering's limestone injection plus wet-scrubbing, (3) Bureau of Mines' alkalized alumina adsorption, (4) Monsanto's catalytic oxidation, and (5) Wellman-Lord's sulfite scrubbing.

It should be recognized that about 20 years are required to go from paper studies through laboratory bench experiments, pilot plants, prototype plants, and commercial demonstration plants to commercial application. Because of this time factor, only the five first-generation processes listed earlier are considered in this report from the standpoint of technical feasibility, applicability, and economic considerations.

Limestone Injection

Technical feasibility: The least complex sulfur dioxide removal system is the introduction into the flue gas of an additive that will unite chemically with sulfur dioxide to form a solid compound. The compound thus formed can then be removed from the flue gas with conventional dust collection equipment. The use of finely-pulverized limestone or dolomite for this purpose is undergoing extensive study.

The relative simplicity of limestone injection as a means of removing oxides from power plant stack gas is a very attractive feature. The boiler serves as the reacter, no complicated regeneration system is needed, and no reheating of stack gas is required. (Figure 4)

Low degree of limestone reaction, however, is a major drawback. Unless new technology for improving sorption is developed, 24 to 35 percent utilization of the injected limestone is probably the highest attainable. Excess limestone can be used to increase sulfur dioxide removal, but adverse effect on power plant operation and cost of removing the increased dust burden from the gas and disposing of it then become major disadvantages.

A full-scale test of a limestone additive system will be conducted within the next year or so on a boiler at TVA's Shawnee Station, Paducah, Kentucky. Construction is to start this fall with several objectives:

1. Test selected limestones for sorption efficiency and slagging problems.

2. Develop an injection system that gives the proper sorbent distribution quickly.

3. Determine point and method of injection that gives optimum initial temperature level for limestone, calcined limestone, and hydrated lime.

4. Gather data on benefit of small particle size.

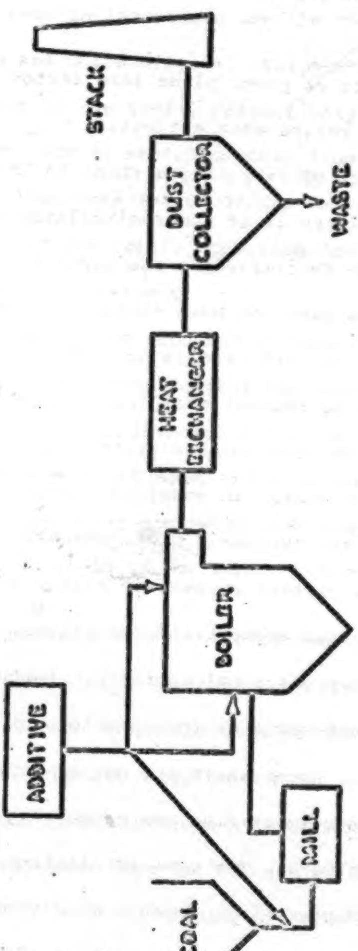


Fig. 4. Limestone Injection

5. Observe effects on power plant operation, including flame stability, heat transfer, slagging, corrosion, erosion, dust collector performance, problems in slaking calcium oxide, and water pollution.

6. Determine effect of power plant load factor on sorption.

7. Gather data to refine cost estimates.

8. Determine effect of recycling sorbent in the recirculating gas (one of the test boilers is of the recirculated-gas type).

Additive testing on smaller-scale equipment is being conducted elsewhere, but variables have not been controlled precisely, instrumentation has been lacking, and results have been erratic.

Applicability: While removal efficiency is not nearly as good as that expected from the more complex systems to be described later, the method may be useful in specific instances. Where the fuel sulfur content is not extremely high, where the plant load factor is low, or where partial removal of sulfur dioxide is sufficient to meet required ambient air conditions, the use of additives may be the most practical approach. Further, the use of additives may be the best solution for operators of commercial and industrial boilers. These units are not of sufficient size to accommodate the more complex flue gas processing systems.

Economic considerations: The cost of limestone injection, both for investment and operation, depends mainly on the amount of limestone used and the size of installation. Simply stated, however, the investment and operating costs for limestone injection

are about three and 10 percent, respectively, of normal power plant costs.

The main items in investment are the increased costs of dust-collection and waste-disposal equipment, representing about 25 and 20 percent of the total, respectively, for a 200-megawatt unit (3.5% S and 200% of stoichiometric limestone). For the operating cost, limestone (at $2.05/ton delivered) accounts for about 45 percent of the total, operation costs make up 24 percent, and capital charges 31 percent.

Conceptual design and economic studies conducted by TVA under National Air Pollution Control Administration contract indicate that the capital investment for the dry limestone injection process for an 800-megawatt power plant would be about $3 million and that the net operating cost when removing 40 to 60 percent of the SO_2 would be about $0.73 per ton. (Table 5)

Combustion Engineering's Limeston Injection Plus Wet-Scrubbing

Technical feasibility: Scrubbing of flue gases with alkaline solutions prepared from materials such as calcined limestone or dolomite, is a well-demonstrated method for removing sulfur dioxide. In one such process under development by Combustion Engineering, the additive is injected into the furnace of a boiler where it is converted by heat to calcium and magnesium oxide. (Figure 5) The oxides carry through the system with the flue gas to a turbulent

TABLE 5

PROJECTED COSTS FOR 800
MEGAWATT FLUE GAS SYSTEM

	Capital Cost $/KW	Owning and Operating Costs $/ton
1. Limestone Injection	3.75	.73
2. Combustion Engineering's Limestone Injection plus Wet-Scrubbing	8.21	.90
3. Bureau of Mines' Alkalized Alumina Adsorption	10.64	1.54
4. Monsanto's Catalytic Oxidation	20.60	1.75
5. Wellman-Lord's Sulfite Scrubbing	11.00	1.49

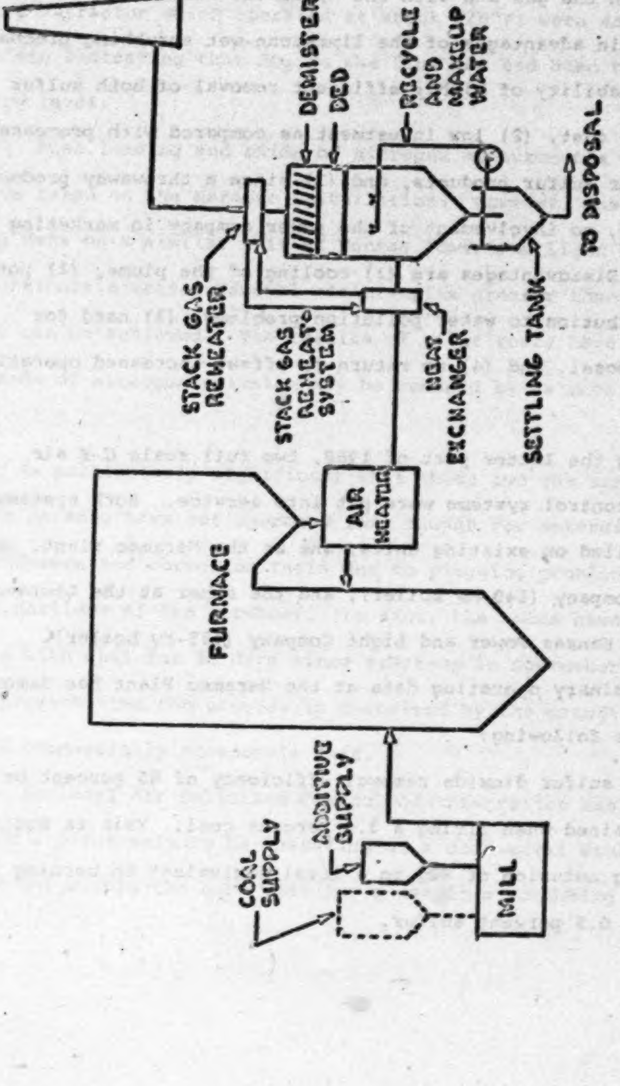


Fig. 5. Combustion Engineering's limestone injection plus wet-scrubbing.

contact absorber where, with water, they form a dilute slurry of alkaline hydroxides. Sulfur dioxide reacts both with the oxides suspended in the gas and with the hydroxide formed in the scrubber.

The main advantages of the limestone-wet scrubbing process are (1) capability of highly efficient removal of both sulfur dioxide and dust, (2) low investment as compared with processes that recover sulfur products, and (3) since a throwaway product is produced, no involvement of the power company in marketing problems. Disadvantages are (1) cooling of the plume, (2) potential contribution to water pollution problems, (3) need for solids disposal, and (4) no return to offset increased operating cost.

During the latter part of 1968, two full scale C-E air pollution control systems were put into service. Both systems were installed on existing units, one at the Meramec Plant, Union Electric Company (140-Mw boiler), and the other at the Lawrence Station of Kansas Power and Light Company (125-Mw boiler).

Preliminary operating data at the Meramec Plant has demonstrated the following:

1. A sulfur dioxide removal efficiency of 85 percent or more can be attained when firing a 3.4 percent coal. This is equivalent to reducing emission of SO_2 to a level equivalent to burning a coal containing 0.5 percent sulfur.

2. The steam generator can be operated with additive injection into the furnace. Low temperature surfaces, including the heat extractor which operated at about 220°F, were easily kept clean indicating that SO_3 in the flue gas had been reduced to a low level.

3. Dust loading and oxide of nitrogen measurements have not been taken on the Meramec installation. However, dust loading data on a similar unit at Kansas Power and Light indicate that particulate matter removal efficiencies greater than 99 percent can be achieved. The results of pilot tests have shown that oxide of nitrogen emission may be reduced by as much as 30 percent.

It is particularly significant that these two gas scrubbing units at Meramec have not operated long enough for determination of performance and corrosion tests due to plugging problems in various portions of the scrubber. In fact, the units have only operated with coal for 31 days since start-up in September 1968. At the present time the process is described by the manufacturer as not a commercially acceptable unit.

The National Air Pollution Control Administration has scheduled a pilot unit to be installed on a commercial size boiler (100-200 MW) within the next year for a wet lime scrubbing program.

(Figure 6) The test program will run 66 weeks to study additives and scrubber variables (using three scrubbers) and then will run an additional 30-50 weeks using optimum conditions for determination of erosion, corrosion, and maintenance factors. Specific variables to be studied include:

1. Variation of absorption efficiency with limestone type and with calcination conditions in the boiler.

2. Variation of absorption efficiency with scrubber type.

3. Effect of particle size on absorbent utilization. This is of particular interest for direct addition of limestone in the scrubber circuit.

4. Use of the delay tank principle in preventing scaling.

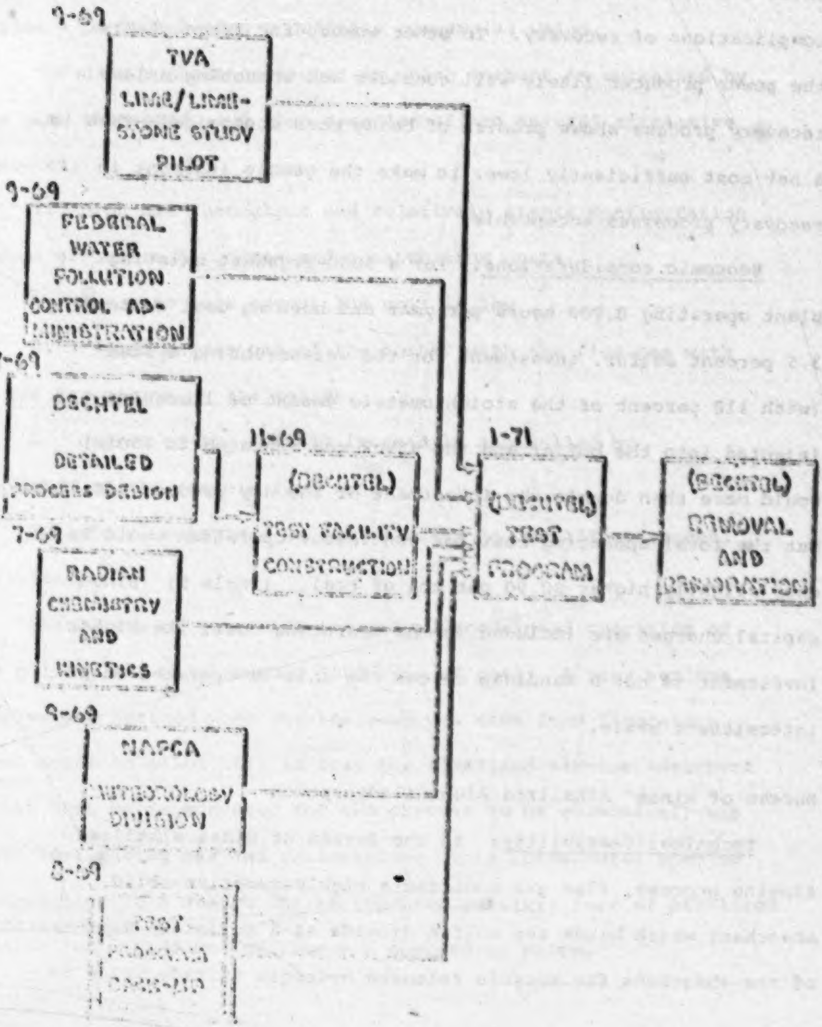
5. Corrosion in the system in extended operation.

6. Effect of oxidation promoters and inhibitors.

7. Chemical and physical properties of scrubber effluent.

<u>Applicability</u>: The wet process is more applicable to new plants since credit can be taken for elimination of dry dust collectors. Also the wet process requires considerably more space for waste water treatment.

The wet process becomes the basic method for comparing with recovery processes, which also are more appropriate for large baseload plants than for units operated intermittently. Because of the high and increasing cost of low sulfur fuel, limestone wet scrubbing will generally be the most economical method for sulfur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TVA
LIME/LIME-
STONE STUDY
PILOT
9-69
FEDERAL
WATER
POLLUTION
CONTROL AD-
MINISTRATION
7-69
BECHTEL
DETAILED
PROCESS DESIGN
7-69
RADIAN
CHEMISTRY
AND
KINETICS
9-69
NAPCA
METEOROLOGY
DIVISION
TEST
PROGRAM
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(BECHTEL)
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AND

oxide control short of entering into the uncertainties and complications of recovery. In other words, for large plants the power producer likely will consider wet scrubbing unless a recovery process shows promise of being more economical--that is, a net cost sufficiently lower to make the gamble inherent in recovery processes acceptable.

Economic considerations: For a 1000-megawatt existing plant operating 8,000 hours per year and burning coal containing 3.5 percent sulfur, investment for the wet-scrubbing system (with 110 percent of the stoichiometric amount of limestone injected into the boiler and the stack gas reheated to 250°F) would more than double the investment of the dry process ($8.21/kw), but the total operating cost for continuous operation would be only slightly higher $0.90 per ton of coal. (Table 5) Since capital charges are included in the operating cost, the higher investment is not a handicap unless the unit is operated on an intermittent basis.

Bureau of Mines' Alkalized Alumina Adsorption

Technical feasibility: In the Bureau of Mines alkalized alumina process, flue gas contacts a highly-reactive solid absorbent which binds the sulfur dioxide as a sulfate. Regeneration of the absorbent for recycle releases hydrogen sulfide which is

converted to elemental sulfur. (Figure 7) Thus, the process yields a product having a definite commercial value.

The dilute phase contactor in which sorbent is entrained by the gas, separated, and then recycled offers several attractive features:

1. High gas throughput and relatively simple configuration reduce ground requirements and construction costs.

2. Pressure loss across the unit is low.

3. Flyash passes out of the sorber with the flue gas with little deposition on the solids.

4. Degree of SO_2 removal is readily controlled by variation of the recycle feed rate.

5. Minor variations in gas velocity do not affect removal efficiency.

The Bureau of Mines has recently discontinued operation of its pilot plant which burned 150#/hour of coal. A very serious problem was noticed when the scale-up was made from laboratory bench scale to pilot unit in that the alkalized alumina adsorbant (which must be regenerated for the process to be economical) was being lost during use and reclamation. This fundamental problem has resulted in a search for an improved particle form of alkalized alumina and withdrawal of research support by NAPCA.

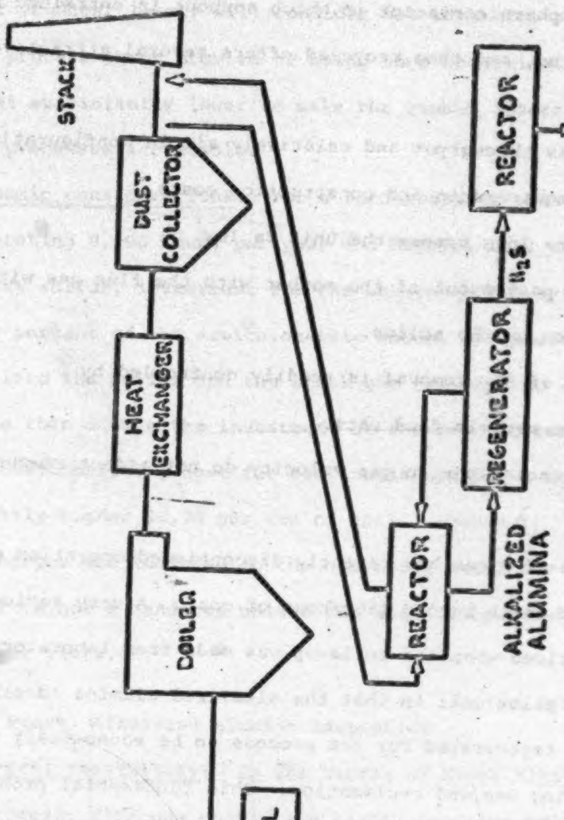

Fig. 7. Bureau of Mines alkalized alumina adsorption.

Applicability: A prototype unit and demonstration size plant would have to be operated successfully at a power plant before commercial applications would be considered.

Economic considerations: An evaluation in which capital and operating costs were estimated for removal of SO_2 from the flue gas of an 800 Mw powerplant was made by the Bureau of Mines prior to contruction of the pilot plant. It was assumed that 90 percent of the SO_2 generated by burning three percent sulfur coal with 20 percent excess air would be removed, and that the power plant would operate with a 90 percent load factor. Capital costs would total $8.5 million. The gross operating costs of $3,402,000 is equivalent to $1.54/ton of coal burned. (Table 5) Credit for recovered sulfur, at current prices, lowers the cost to about $0.50/ton of coal.

However, a recent study for NAPCA by M. W. Kellogg of conceptual design and cost analysis estimated a minimum operating cost of $3.60 per ton not including attrition loss of the adsorbent, not including generation of reducing gas, and not including the Klaus recovery plant. Because of these present economics and the technical problems, NAPCA is phasing out research funds for this sulfur oxide removal project.

Monsanto's Catalytic Oxidation

Technical feasibility: A more complex system of SO_2 removal

is catalytic oxidation. Monsanto, one of several companies researching this method, has developed a prototype system. (Figure 8) Hot furnace gases first pass through a highly efficient electrostatic precipitator (over 99.5 percent) where fly ash is removed. Gas from the precipitator is then passed through a converter where the SO_2 is catalytically oxidized to SO_3. Cooling is accomplished by using an economizer and air preheater which are designed to maintain the gas above its dew point. The SO_3 reacts with the water vapor in the flue gas and is condensed in a packed-bed absorbing tower as sulfuric acid at an average concentration of 80 percent. A mist eliminator then separates and collects the acid mist from the flue gas.

The feasibility of the Cat-ox system was established over seven years ago in a pilot operation at Pennsylvania Electric Company's Seward, Pennsylvania, generation plant. In mid-1967, Monsanto, in cooperation with Metropolitan Edison Company, began operation of a prototype plant built at the Portland, Pennsylvania, generating station. Although the facility has a generating capacity of 250 Mw, the prototype plant is designed to treat about 24,000 std. cu. ft./min. of stack gases which represents only about six percent of the total flue gas.

The major disadvantage to this process is that hot flue gases are required to produce catalytic conversion and the sulfur is

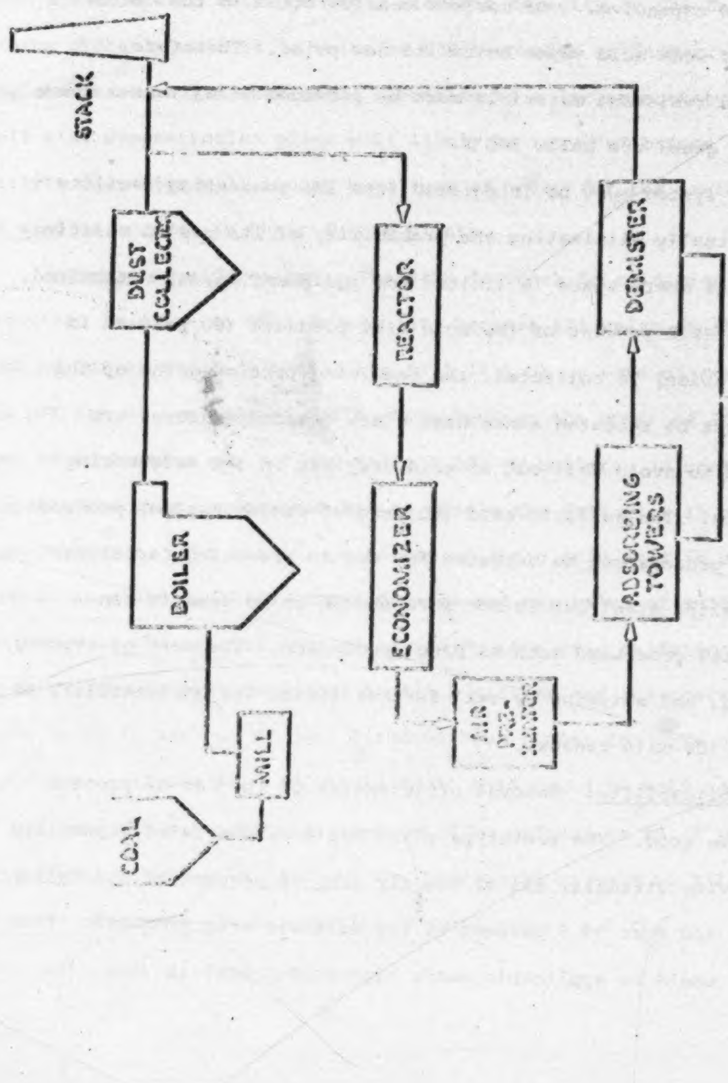

Fig. 8. Monsanto's catalytic oxidation.

removed in the form of a relatively weak sulfuric acid. High-temperature high-efficiency electrostatic precipitators are bulky and expensive. Of serious consideration is the corrosive nature of weak acid vapor below its dew point. Therefore, corrosive resistant materials must be provided in all areas where the flue gases are below 500°F.

The system must be integrated into the generating facility thus virtually eliminating the probability of its use in existing facilities where space is limited and equipment layout determined. Although 99.5 percent of the acid mist produced (80 percent in concentration) is collected, the remaining portion going up the stack must be reheated since high stack gas temperatures are required to avoid fall-out of acid droplets in the neighboring community. The sulfuric acid (80 percent concentration) produced by this process can be marketed for use in producing fertilizer and pickling steel but is not pure enough to be used in non-industrial processed such as drug production. The cost of storing, handling, and shipping by rail further limits its marketability to about a 100-mile radius.

Applicability: Removal efficiencies of the Cat-ox process are quite good. The prototype plant has a demonstrated capability of removing virtually all of the fly ash, 90 percent of the sulfur dioxide and over 99.5 percent of the sulfuric acid produced. This process would be applicable where high sulfur coal is used. In

theory, the larger the generating plant the more economical this system becomes. Projected power generating figures indicate that by 1980 a little over half the total electric capacity in the United States probably will be in units of 600 megawatts or larger. However, the construction and successful operation of a larger prototype or full size demonstration plant will likely be required before the utility companies will invest huge sums of money for the installation of similar systems in their future plants.

Economic considerations: The main drawback to oxidation or reduction in place is high investment, because all units of the system must be large enough to handle the full 12 tons or more of combustion gas per ton of coal burned, or a throughput on the order of 110,000 tons of combustion gas per day for a 1,000 Mw boiler. In contrast, only the absorber or scrubber has to handle the full flow in sorption-type processes. The netback price for sulfuric acid sold is dependent on plant location, local demands and the value of sulfur. For example, the capital cost of an 800 Mw catalytic oxidation installation has been estimated at $16.5 million and the operating costs at $1.75 per ton of coal fired without credit for sale of byproduct. (Table 5) If the sulfuric acid could be sold for $9 per ton, the net operating cost would be reduced to $0.72 per ton of coal fired or to $0.38 if the acid could be sold at $12 per ton. However, the fluctuation in acid prices and the

uncertainty of the long-term market detracts from its strongest selling point--namely, the full or partial recovery of operational costs through the sale of sulfuric acid.

Wellman-Lord's Sulfite Scrubbing Process

Technical feasibility: The highly secretive Wellman-Lord sulfur dioxide recovery process reportedly represents a new approach in the field of air pollution control; however, it bears some similarity to the catalytic oxidation and the aklalized alumina process. (Figure 9)

In this process the sulfur-laden flue gases are first cleaned in a high-temperature high-efficiency electrostatic precipitator and then passed through a noncatalytic reactor which is continuously washed by a reactive solution. The residual particulate matter and sulfur trioxide adhering to it are trapped in the solution and removed by a continuous blowdown. The sulfur dioxide is disolved in the process solution which is sent to a stripping column where steam is added to release the sulfur dioxide as a wet gas of very high purity. The wet SO_2 vapor is compressed and recovered as pure liquid SO_2 from a rectification tower.

The process was only conceived in mid-1966 and a pilot plant was installed early in 1966 at the Cannon station of the Tampa Electric Company where it is in operation at the present time. A 25 MW plant processing 60,000 ACFM flue gas was started up early

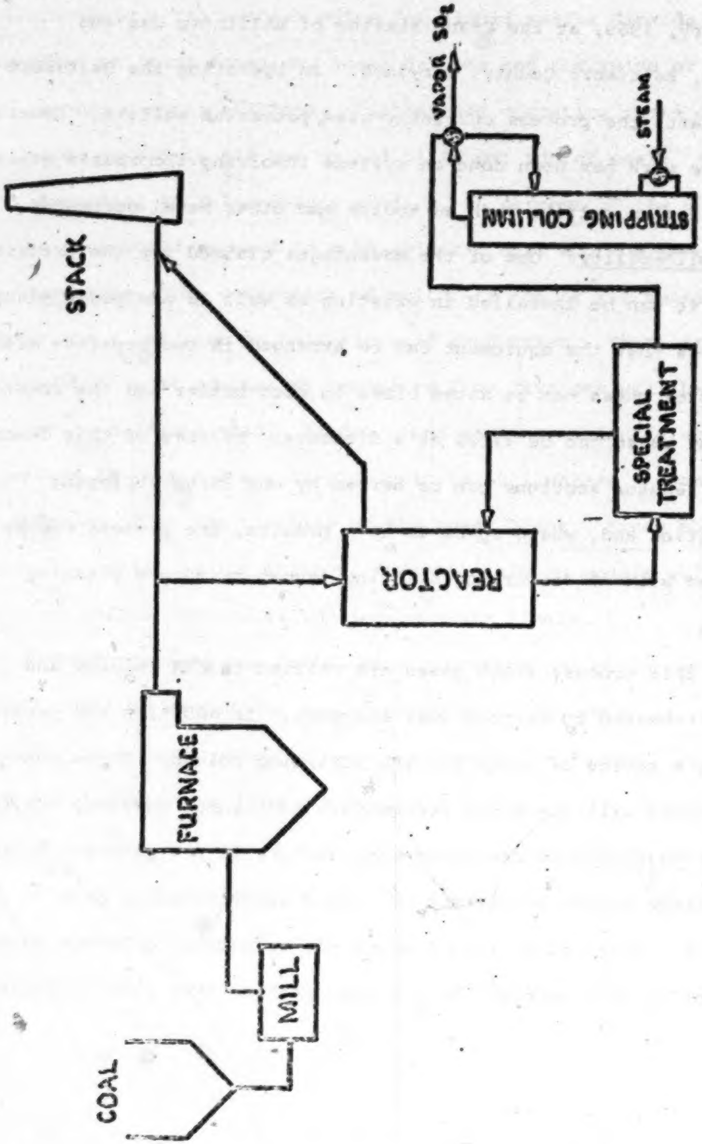

Fig. 9. Wellman-Lord SO_2 Recovery Process.

in January, 1969, at the Crane station of Baltimore Gas and Electric, Baltimore County, Maryland. In operating the Baltimore pilot plant, the process currently uses potassium sulfite. However, extensive work has been done on systems involving absorbants other than potassium sulfite such as sodium and other metal compounds.

Applicability: One of the advantages claimed for the process is that it can be installed in existing as well as new power plants. Another is that the equipment can be arranged in two separate areas. The reactor phase can be sited close to each boiler and the chemical stripping phase can be sited at a distance. Because of this feature several reactor sections can be served by one large stripping installation and, where space is at a premium, the process can be installed without disturbing existing layout or future planning programs.

In this process stack gases are chilled in the reactor and must be reheated to restore lost buoyancy. In addition the process requires a source of steam for the stripping column. These energy requirements will therefore necessitate additional auxilary boilers in existing plants or oversized main boilers in new plants. Another disadvantage is the production of liquid sulfur dioxide as a byproduct. Most utility managements are reluctant to become engaged in marketing this product for the same reasons they dislike marketing

sulfuric acid. The netback price for liquid sulfur dioxide is dependent on plant location, local demands and the value of sulfur.

Economic considerations: Capital and operating costs are estimated at $10 to $11 per Mw and $1.49 per ton of coal. (Table 5)

According to Wellman-Lord studies, 85 percent of the sulfur in the free world is used to make sulfuric acid and the percentage is increasing. The conversion of sulfur to SO_2 or the receipt of SO_2 is the first step in sulfuric acid production. Thus, it is assumed that most of the SO_2 recovered from flue gas will be used to produce sulfuric acid. As described earlier, sulfuric acid is expensive to ship and may be difficult to sell unless it can be disposed of in the vicinity of the power plant. Since the process is still in its infancy, further scale-up models will be required before commercial applications are likely.

Within the next ten years, many processes for sulfur oxide removal will be tested and further developed. However, it is unlikely that many commercial applications will be made. Of the five first-generation flue gas desulfurization methods discussed in this report, two (wet and dry limestone injection) do not produce usable byproducts whereas the remaining three produce various sulfur bearing byproducts. For continuous operation in base load plants the wet scrubber is more desirable due to its

higher efficiency of sulfur oxide and dust removal. For existing small generating plants the dry limestone injection offers more potential. However, both processes are still being developed by the National Air Pollution Control Association and many questions remain to be answered before commercial applications can be expected.

When comparing the three flue gas processing methods which produce a byproduct, the Monsanto cat-ox system is considered technically ahead of the other two. It is, by far, the most expensive to install and operate even though all three require heavy capital expenditures. Also all three methods produce a sulfur byproduct that would force the steam-electric utility's management into becoming chemical producers. Since sulfur and sulfuric acid prices constantly vary, utilities are not likely to readily accept these processes. The alkalized alumina process in theory is very promising since its proposed byproduct is elemental sulfur. However, this method developed serious problems when tested at the pilot plant level and development work has been drastically reduced. The Wellman-Lord Sulfite Scrubbing process seems the most economical but this process is still in its infancy and will require years of testing from its present small scale facilities before commercial installations will become reality.

Over the long term, it is reasonable to expect that planning for large new steam-electric plants will consider the need for

reducing sulfur oxide emissions as well as for removing particulate matter which is common today. Such planning will likely take into consideration the economics of alternate fuels, alternate fuel cleaning procedures, and stack gas cleaning methods.

CONCLUSION

In sum, coal consuming facilities in most industrial areas in the midwest will be increasingly forced to take positive action to control or indeed eliminate sulfur oxide emissions. For many, conversion to other fuels will represent the only practical means of compliance. For other energy users, the cost and time tables of abatement strategies discussed in this report will be carefully weighed before final decisions are made as to fuel or energy source and location of facilities. Over the next 10 years, air pollution limitations will have a serious impact upon coal's marketing patterns and its share of energy markets. Beyond that period, such limitations may well continue to constitute an important competitive handicap to coal's ability to compete with other energy sources.

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1969 Highlights

DX 90 Commonwealth Edison Annual Report

	1969	Change Since 1968	Average Annual Change Since 1959[1]
Net Income on Common Stock	$126.1 million	up 0.5%	up 4.8%
Earnings per Common Share	$3.00	up 0.3%	up 4.6%
Cash Dividends Paid per Share	$2.20	—	up 8.7%
Electric Operating Revenues	$801.1 million	up 7.6%	up 6.4%
Average Residential Revenue[2]	2.53¢/kwh	down 1.2%	down 1.7%
Sales to Ultimate Consumers	42.9 billion kwh	up 8.1%	up 7.8%
Average Residential Use	5,174 kwh	up 6.9%	up 7.0%
Electric Customers at December 31	2.84 million	up 2.2%	up 1.7%
Peak Load	9.27 million kw	up 3.5%	up 8.4%

(1) Central Illinois Electric and Gas Co. figures included for periods prior to the December 9, 1966 merger.
(2) Excludes light bulb service.

Letter to stockholders

How to preserve our air, water and land is the question of the day. Our public is concerned and so are we. We also are concerned in the public interest about an adequate and uninterrupted supply of energy. We know from experience that the public demands it.

Because of these concerns I feel I should give you my views as to how electric power supply should be handled in the long-term future to minimize intrusion upon our environment.

First, large generating complexes should be located away from urban areas. These complexes can make use of several power sources. They may be fossil-fired, present-day nuclear machines, or breeder or fusion reactors. Nuclear units and their successors will be in every way fine neighbors. Quiet. Absolutely safe. No long strings of coal cars. Not a trace of smoke or soot. And designed to satisfy tough water temperature standards.

These generating complexes should be linked to each other and to city and industrial load centers. The result will be a grid with stations and transmission lines of great capacity.

Huge power demands require big units and big interconnecting lines. Even with our present technology we are building them with almost no adverse ecological effect. Fortunately, such a bulk power system is not only the most reliable but also the most economical. This means smaller power systems may increasingly choose not to make their own electricity, but instead to buy it from larger complexes built by larger companies. Law and custom may resist this, but technology, economy and environment may require it.

In our business, we must plan and begin construction years ahead of need. To anticipate public wishes in a timely way, we can accent one or another of the environmental alternatives which technology and economy allow. But stations cannot be rebuilt overnight. New nuclear units do not spring magically from the ground. Fuel sources take time to develop and to modify. Nevertheless, we have done much quickly, and we shall do more soon. We will eliminate our share of pollution in just as short a period as meeting our electrical commitments to the people of Illinois will allow.

And there is no doubt in my mind that we will furnish power in the future in a way that makes northern Illinois a better place in which to live.

Sincerely,

J. Harris Ward
Chairman

1969 Review

Earnings, dividends flat
Our earnings for 1969 were $3.00 per common share, virtually unchanged from 1968's level of $2.99 or 1967's $2.98. Net income on common stock totaled $126 million, about the same as that of the prior year.

Dividend payments during 1969 were $2.20 a common share, the same as in 1968, and only 10 cents more than in 1967. This leveling off in earnings and dividend growth contrasts with good increases in the preceding years.

Stockholders are entitled to a competitive return on their investment. To supply this and to compete effectively in the money markets, we require a rate increase.

Good sales performance
This need for rate relief is not caused by lagging sales growth. During 1969, each of our four major classifications of kilowatthour sales and revenues had fine increases. Electricity sales to ultimate consumers increased 8.1 percent over 1968, and related revenues had a 7.8 percent gain. These compare with average annual increases of sales and revenues during the 1960's of 7.4 and 5.4 percent. It is nice to close out the soaring sixties with increases which are well above average for the decade. We are confident about Edison's ability to continue to increase—at a good pace—its sales and revenues during the 1970's.

At December 31, we had 2.54 million customers on our lines, 2.2 percent or 55 thousand more than at the end of 1968.

1969 Revenues and Sales	Electric Operating Revenues (thousands)	Increase Over 1968	Kilowatthour Sales (millions)	Increase Over 1968
Residential	$303,981	7.9%	11,826	9.2%
Small commercial and industrial	286,199	6.0%	13,378	6.6%
Large commercial and industrial	139,443	10.2%	13,781	9.4%
Public authorities	48,650	9.0%	3,593	8.6%
Electric railroads	5,355	—	385	—
Ultimate consumers	$783,628	7.8%	42,933	8.1%
Sales for resale	9,767		1,454	
Other revenues	7,754			
Total	$801,149		44,387	

3

Expenses up $47 million
Electric operating expenses during 1969 totaled $425 million, $47 million or 12.4 percent higher than last year. $28 million of the increase was due to higher fuel and purchased power expenses. This was a result of having to buy higher cost fuel and more of it, and—among other purchases—of having to import power to cover Dresden 2's delay.

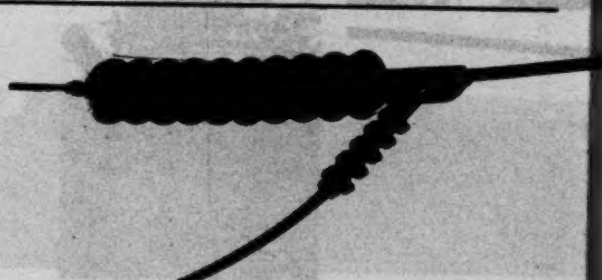
Other operation and maintenance increased $12 million or 7.6 percent, due mainly to higher payroll costs. Added plant pushed depreciation expense up $7 million or 7.4 percent.

Taxes cut earnings
During 1969 we paid or set aside $207 million in state, federal and local taxes of all kinds and sizes.

A burdensome new 1969 tax was the Illinois income tax, levied at 4 percent for corporations. The state income tax was effective on August 1 and cost stockholders 3 cents per share on 1969 earnings. We estimate the 1970 effect to be on the order of 8 cents. On the other hand, reduction in the federal income tax surcharge should help to offset 1970 increases in taxes and other operating costs.

1969 Electric Operating Expenses	1969 (Thousands)	Increase Over 1968
Fuel and purchased and interchanged power (net)	$154,351	22.2%
Other operation and maintenance	170,615	7.6%
Depreciation (straight line)	100,941	7.4%
Total	$425,907	12.4%

Power for People in the '70's is the theme of this report. Edison facilities, like this strain insulator, tie together the vital activities of northern Illinois. Shown here are a man on Ford's Chicago assembly line, one of our nuclear plants under construction, and Amoco's refinery near Joliet.



Interest costs jump 26%
Interest charges on debt during the year were $62 million, up $13 million or 26 percent over 1968. This big increase was due to new bond issues and interim short-term financing at record-breaking interest rates. Regardless of capital costs, we must raise the money required to carry out our construction program. We expect another sizeable increase in interest costs during 1970.

Progress on rate request
On August 15, 1969 we filed with Illinois Commerce Commission proposed new rates which provided for a 6.1 percent revenue increase. The Commission must render a decision within 11 months of initial filing or, in our case, by July 13, 1970. We, of course, hope for an earlier ruling and are doing all we can to hasten the hearings.

Under Illinois law, we are entitled to rates which give us the opportunity to earn a fair return upon the fair value of our plant. Establishment of fair plant value involves among other things "the fair consideration of current price levels, . . . the ultimate purpose being to determine and allow a fair return to the owners . . ." Fair value is less than today's replacement cost, but it ought to be substantially more than original cost. In these inflationary times, fair value is a far more just standard than original cost.

We do not like rate increases because they impair our ability to compete in the energy market. Indeed, in the 1960's we reduced our customers' rates time after time. However, inflation has more than counterbalanced our cost-control efforts, and we have reluctantly applied for a rate increase.

Why rate relief vital
The captions in this annual report tell the story: "Earnings, dividends flat", "Expenses up $47 million", "Taxes cut earnings", "Interest costs jump 26%", "Plant budget up $250 million", "$395 million for 1969 construction", "$1 billion of new securities needed", "Wages up 6%, benefits higher". The pressures of rising expenses are heavy and have in turn leveled our earnings.

Our business is growing rapidly and we must expand our facilities to serve it. But since 1965, our generating station construction costs per kilowatt have risen by up to 80 percent, and interest rates have nearly doubled. We must meet expanding load commitments with far more expensive new facilities. The result is the largest construction budget in our history which must be financed at near-record interest rates.

Today's investors require far higher returns than they once did, and we must pay their price to use their money. To attract capital we need greater earnings. In short, we need a rate increase.

A modest request
A 6.1 percent rate increase request is modest. Other electric power companies around the country have asked for far more. We did not request 6.1 percent in the hope of getting something less. Instead, we asked only for the amount we must have, and we hope to receive that amount in full.

Preserving Lake Michigan
Clean air and water is an idea whose hour has come. The center insert of this report outlines what Edison is doing to reduce pollution. We are deeply concerned, and recognize that others are, too. Not all concerns, however, have equal basis in fact, and a recent example of this has to do with Lake Michigan.

6

These finely machined control rod drive housings in an Edison nuclear plant help provide electricity to people in farms and homes across our 13 thousand square mile service area.

Zion safe for lake
Two suits were brought last fall to halt construction of our Zion Nuclear Power Station. Each claimed that Zion would damage Lake Michigan. Zion Station will not harm Lake Michigan.

Zion Station is being built under rigorous Atomic Energy Commission standards. The water returned to the lake at Zion will be safe. In fact, insofar as radioactivity is concerned, one could drink it for a lifetime without harm.

Our extensive studies indicate that fish and plant life will not be injured. Indeed, one of the best fishing spots in our area is off our Waukegan plant, south of Zion. The amount of water passed daily through Zion's sealed condensing system will be roughly equivalent to circulating one pint of tepid water in a good sized swimming pool.

The temperature of the water returned to the lake will be under 85 degrees, meeting the limits set by the State of Illinois and approved by the U.S. Department of the Interior. Indeed, the Federal Water Pollution Control Administration has stated that the combined annual effect of all existing plants plus all proposed nuclear plants on Lake Michigan would raise overall lake temperature by less than 1/10th of one degree Fahrenheit. Even this small rise tends to cancel out each winter. Interestingly, the average annual temperature of the lake has actually dropped about two degrees in the past century.

Gas negotiations begin
In December, Edison made a joint announcement with Northern Illinois Gas Company that negotiations were under way for acquisition of our subsidiary, Mid-Illinois Gas Company.

We have been approached by several companies in addition to Northern Illinois. Since we have a valuable commodity, we expect to be able to make an agreement which is fair to our stockholders, protects our gas employees, and is in the public interest. We anticipate that arrangements will be completed during 1970.

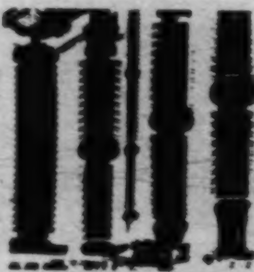
CILCo merger talks ended
During 1968 and 1969, we conducted talks with Central Illinois Light Company on the possibility of merger with Edison. In June, 1969 we made an offer which would have allowed CILCo's common stockholders to elect securities giving them premiums of over 85 percent on income and 25 percent on market price. In October, CILCo's management rejected our terms and broke off negotiations. We do not expect the talks to be reopened.

Peak summer load
A record peak load of 8.3 million kilowatts was set July 16. This was only a 3.5 percent increase over 1968's highest load, compared with an unusual 17 percent rise between 1967 and 1968. Because of the variability of summer weather, we have come to expect that heat sensitive loads will not march evenly upward year after year.

On the average, however, our summer peak loads are growing at over 8 percent each year. To meet them our engineers, purchasing and construction people must plan, buy, build and bring into effective service hundreds of millions of dollars worth of new plant each year. The range between extravagance and perfect investment economy on a system the size of Commonwealth Edison's must surely exceed several hundred millions of dollars. For example, last fall a national magazine estimated that by purchasing four nuclear units at fixed prices Edison had saved "about $330 million."

Fast-start peaking units
During 1969 we placed on our system 535 thousand kilowatts of fast-start peaking capacity, bringing our total of such equipment to 1.34 million kilowatts, more than any company in the country. An additional 380 thousand kilowatts have been ordered for 1970 service, though about 200 thousand kilowatts may miss the summer peak due to the General Electric strike.

Homes are heated with the help of these insulators at one of our 135 transmission substations.



Generating capacity additions

Unit	Type	Scheduled for		Net Capacity (kilowatts)
Dresden 2	Nuclear	Spring	'70	800,000
Peaking	Gas & Oil	Spring, Summer	'70	380,000
Dresden 3	Nuclear	Winter	'70-'71	809,000
Quad-Cities 1	Nuclear	Spring	'71	800,000*
Quad-Cities 2	Nuclear	Spring	'72	800,000*
Zion 1	Nuclear	Spring	'72	1,100,000
Powerton 5	Coal	Spring	'72	840,000
Zion 2	Nuclear	Spring	'73	1,100,000
None	—		'74	—
None	—		'75	—

*Iowa-Illinois Gas and Electric Company has a one-quarter ownership interest in the two Quad-Cities units.

These machines are economical for meeting short periods of peak demand because their low capital costs offset their higher fuel costs. They burn gas or oil and can be brought on line in small increments on short notice. Perhaps best of all, the fast-start units allow us to retire smaller coal-fired boilers around the City of Chicago, and thus contribute to our efforts to curb air pollution.

First big nuclear unit
This spring Dresden 2, the first of our large second generation nuclear units will be placed in commercial service, and should be starting up as you read this report. Dresden 2 has an ultimate capacity of 809 thousand kilowatts and will be followed within about a year by two more nuclear units, Dresden 3 and Quad-Cities 1.

These plants must meet rigorous construction standards before being granted an operating license by the Atomic Energy Commission. Because of the care with which they have been built, we expect them to be absolutely safe, and more reliable than any of our large coal-fired units. Nuclear units produce electricity without smoke, soot or dust, and are, therefore, the keystone of our clean air program.

Pumped hydro power
Nuclear generation also fits well with pumped hydro generation. We are negotiating with Consumers Power and Detroit Edison for a 624 thousand kilowatt share of their Ludington, Michigan pumped hydro generating plant. Power would be purchased under a long-term agreement to begin in 1974.

Electrical demands are lower at night and so nighttime energy is most economical for us to produce. During the night, energy from our nuclear units would be employed to pump water to an elevated storage reservoir on the eastern shore of Lake Michigan. During daylight hours the water would be released, electricity generated, and the energy returned to us over high voltage transmission lines.

Skilled people controlling intricate machines—computers, airplanes and Edison junction boxes—make our electrified urban society possible.

On average, about three off-peak kilowatthours would be used up for every two on-peak kilowatthours generated. However, high daytime and low nighttime demands plus around-the-clock loading of our nuclear machines make the transaction an economic one. Also, this and other power purchase agreements will allow us to forego construction of any major generating units for 1974 and 1975 service.

In the nearer term, purchased power contracts, strong interconnections, our fast-start peaking units, and the larger units coming on in the early 1970's should provide adequate reserve margins for meeting the needs of our northern Illinois service area.

Plant budget up $250 million
For electric generating units, transmission lines, distribution facilities and other plant, we plan to spend $1.95 billion during the five years 1970 through 1974. This compares with $1.7 billion budgeted for the period 1969–1973.

The increase from $1.7 to $1.95 billion for the different budgeting periods results in part from the strong sales growth we expect. However, inflation and environmental considerations also play their parts.

The new $1.95 billion budget includes expenditures of $520 million in 1970, $470 million in 1971, $305 million in 1972, $280 million in 1973, and $375 million in 1974.

The totals after 1971 are somewhat lower than they would otherwise be because no major generating units are scheduled to begin service in 1974 or 1975. Allowance has been made, however, for initial outlays for construction of 1976 and 1977 units.

A man involved in his work and a steel furnace ladle are both served by graceful 138 thousand volt transmission lines.

Air Pollution in the Chicago Area

What Commonwealth Edison is doing to help reduce it, and what we will do, and when.

". . . everybody—beginning with ourselves—must do more to make our city, our nation, our world, a better, brighter, sweeter (and not just richer) place for us and our children to enjoy."

Air pollution is a serious matter, for all citizens in every city, in every developed country in the world.

It is too serious to become a political football, or an emotional and partisan issue, or a platform on which companies can thump their chests and proclaim their virtue and good citizenship. Deeds, not words, are what the public is looking for—and has a right to get.

Commonwealth Edison has already spent $83 million on facilities to prevent contaminants from getting into the air; and is spending hundreds of millions on new nuclear stations which add *no* fumes or dirt to the air.

But it is beside the point that we have spent "x" millions of dollars, and committed millions more.

What *is* important is not so much what we have done as what we will do. We recognize the gravity of the problem, and accept the plain fact that everybody—beginning with ourselves—must do more to make our city, our nation, our world, a better, brighter, sweeter (and not just richer) place for us and our children to enjoy.

The Rules We Live By
Years ago, Commonwealth Edison decided that we had these obligations to the community:

1. To provide the amounts of electricity needed, where needed and when needed, within the area we serve, and reserve margins to handle emergency conditions.

2. To do this at the lowest possible cost to the consumer.

3. To anticipate future needs, often involving years of lead-time for the manufacture and installation of necessary facilities.

4. To do all this while minimizing actual and potential pollution.

". . . the waste particles which people call 'smoke' can be almost entirely prevented from escaping into the air . . ."

Electric Power and Air Pollution
Commonwealth Edison produces and distributes the electricity on which practically every home, office, store, and industry in our entire area depends.

Our product heats and air-conditions the 100 story John Hancock Center and runs the elevators that make such a building possible. It lights your home, operates your TV set, and may even brush your teeth.

Electricity must be always on tap, day or night, at the flick of a switch. It can't be stored until you need it. Most people have come to take it for granted.

How does Commonwealth Edison produce electricity? Chiefly by heating water in giant boilers to make steam power, which turbines and generators convert into electric power.

We have three types of boilers: coal-fired, natural gas or oil-fired, and nuclear-powered.

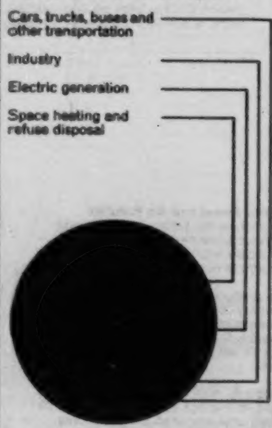
Nuclear reaction emits no fumes or smoke. Natural gas or oil burning releases some, but not much. Coal burning releases more, including sulfur oxides, but the waste particles which people call "smoke" can be almost entirely prevented from escaping into the air by the use of modern electrostatic precipitators.

Before
This stack at our Joliet Station has its electrostatic precipitator disconnected to show how much smoke would escape.

After
Soon afterward this unretouched photo shows the unit still in full operation—but with its modern precipitator connected.

"... we account for less than 5 percent of all contaminents in the air you breathe."

Sources of Air Pollution
The principal sources of air pollution nationally, according to an authoritative report by the National Academy of Sciences ("Waste Management and Control"), are about as follows:



These are national figures. In the case of Commonwealth Edison, although we burn two-thirds of all the coal burned in the Chicago area, our control and dispersion methods are so effective that we account for less than 5 percent of all contaminants in the air you breathe. Included in this 5 percent figure are sulfur oxide emissions. Most of the ground-level sulfur oxides come from homes, stores, factories and apartment buildings which lack the tall stacks of our stations.

Our Plan of Action
1. To cut in half, within the near future, the amount of coal we burn in and around Chicago, and then to reduce it still more.

2. To continue to improve our electrostatic precipitators. Our goal is to try to have every precipitator prevent 98 percent or more of waste particles from the coal we burn from getting into the air.

3. To increase as rapidly as possible the share of nuclear power in our total production.

4. To use all the natural gas we can get. To introduce new low-sulfur oil. And to continue our efforts to obtain and burn low-sulfur coal.

Here are details of our Plan of Action:

1. We Are Reducing the Amount of Coal We Burn
The best way for us to help reduce air pollution is to burn less coal. This is not easy when the demand for electricity continues to grow.

Still, this is what we are achieving:

	Coal (million tons) burned in Chicago area	Electricity (billion kwh) used in Chicago
1965	6½	14
1970 (Est.)	4	18
1975 (Est.)	3¼	24

These reductions are made possible in part by our nuclear program and by converting an entire generating station from coal to low-sulfur oil.

Also, within the last two years we have installed 1.24 million kilowatts of fast-start generating units (another 380 thousand in 1970), which burn only gas or oil and will permit retirement of an entire Chicago coal-fired station.

2. We Are Installing More and Better Precipitators
Commonwealth Edison began installing precipitators as long ago as 1929. They have been steadily improved to reach their present levels of efficiency. The newest electrostatic precipitators prevent all but a small amount of the "particulates," or waste particles from the coal we burn, from getting into the air.

All coal-fired boilers in our metropolitan area stations are equipped with precipitators. We have a few precipitators left that are not yet 98 percent efficient, but we're working hard to finish upgrading them.

We have retired 47 coal-fired boilers in Chicago within the past ten years. We presently plan to have only nine left in Chicago by the end of this year.

"Commonwealth Edison is complying, and will continue to comply in full, with all government laws and regulations on air pollution . . ."

3. We Are Rapidly Increasing Our Nuclear Production of Electricity
Commonwealth Edison pioneered in the development of nuclear power nearly 20 years ago. Our first nuclear unit has been operating successfully at Dresden for ten years.

We now have six large nuclear units under construction, two each at Dresden, Quad-Cities and Zion.

The first is scheduled to be in operation this spring. All will be in operation by 1973.

Clean-Air Pellets: Each of these tiny nuclear pellets contains as much energy as a ton of coal. They produce electricity without any fumes, smoke or soot.

About 40 percent of our vastly greater production of electricity will then be from nuclear stations, which emit no fumes or smoke. Our $800 million nuclear program is the largest of any investor-owned electric power company in the United States.

4. We Are Using Natural Gas and Low-Sulfur Oil, Testing Low-Sulfur Coal, Researching the Removal of Sulfur Oxides
Natural gas is available to us only in limited quantities. We are using all we can get.

We recently announced the 1970 conversion of our Ridgeland Station (in Stickney, Illinois, immediately west of Chicago) to low-sulfur oil-burning equipment. Ridgeland was chosen because its stacks must be lower than those at other stations due to its nearness to Midway Airport.
This conversion alone will eliminate the burning of 1.3 million tons of coal a year.

Another way to reduce air pollution is to use coal with low-sulfur content. There is low-sulfur coal in Montana, Wyoming, and Colorado, and we have been testing it. We haven't yet found any we can burn successfully, because our boilers and precipitators were not designed for it. Eastern low-sulfur coal appears to present even more severe problems. But we continue to test.

We have long participated in efforts to develop advanced methods of removing gaseous sulfur oxides from stack gas. Recently we have joined with 15 other electric power companies, Esso Research and Engineering Company and Babcock & Wilcox Company in a $7 million program for the development of an advanced air pollution control system of this kind.

Commonwealth Edison is complying, and will continue to comply in full, with all government laws and regulations on air pollution, including Chicago's Pollution Control Ordinance.

This ordinance, effective in July, 1970, requires that sulfur emissions be lowered in progressive steps through 1974. The ordinance can be complied with either by burning less coal or lower sulfur coal.

We are following the first route, by cutting our coal burn in half, and we will meet the timetable of the ordinance.

This is better than just cutting the sulfur content of the coal because all combustion products are reduced. The ordinance requires approval of our plan to do so, and we have applied for this.

$396 million for 1969 construction
During 1969 construction expenditures were $396 million and plant retirements and adjustments $30 million. Our gross investment in plant and equipment at December 31, was $3.7 billion. In addition, our nuclear fuel investment totaled $71 million.

$1 billion of new securities needed
In the five years 1970–1974, about $1 billion of new securities must be sold to help pay for new construction and nuclear fuel. This is in addition to our January, 1970 bonds and refunding of about $275 million of bonds during the period.

We have announced that we expect to market $100 million of equity securities during 1970, probably towards the end of the year.

Short-term bonds
In the course of 1969, $175 million of first mortgage short-term bonds were sold. In April, $75 million of five-year bonds were issued at an annual cost to the Company of 7.42 percent before expenses. Because of strong demand, the issue was increased from $50 million to $75 million. In July, $100 million of four-year bonds were sold by competitive bidding at an annual cost of 7.73 percent before expenses.

We postponed another $100 million of five-year first mortgage bonds from November, 1969 until early January, 1970 because of what appeared to be an interest rate peak. In the January negotiated sale these bonds had an annual before-expenses cost to Edison of 8.61 percent. Though it cannot be precisely determined, we seem to have saved about half a percent by delaying the issue. If true, this amounts to perhaps $2 million in interest savings over the five-year life of the bonds.

In the '70's, this young man probably will seek his first job. He might eventually become an editor, a skilled craftsman or a computer programmer. Whatever his employment, he and hundreds of thousands like him will need increasing amounts of electricity.

1969 funds statement	(Thousands)
Funds provided by:	
Net income less dividends	$ 33,585
Depreciation and tax deferrals	118,413
Funds provided internally	$151,998
Sales of securities	179,728
Bank loans and commercial paper (net)	86,075
Change in working capital and other items	21,487
Total funds provided	$439,288
Funds applied to:	
Construction expenditures	$396,261
Nuclear fuel expenditures	36,285
Sinking fund debt retirements	6,742
Total funds applied	$439,288

A new bond-buying public
It appears that a new market is developing among smaller investors for these short-term issues. On the two 1969 sales totaling $175 million, about 10 thousand separate holders have been registered with the mortgage trustee. This contrasts with about a third that number registered for $175 million of 30-year, long-term Edison bonds sold during 1968. We are glad to be reaching this mass market of smaller investors.

Other 1969 financing
As we have done in the recent past, we used commercial paper (notes payable) in 1969 to allow ourselves choice in timing debt issues. At December 31, 1969 we had $86 million in commercial paper outstanding.

Commercial paper costs money. Short-term rates have been no cheaper than long-term ones and cut into earnings in the same manner. Our assumption in using short-term bonds, commercial paper and bank loans is that the staggering interest rates now being charged will decline sooner or later, and that we should avoid being locked into long-term obligations at the current high rates.

In the fall of 1969 Edison renewed $80 million in bank loans at the prime rate from Chicago banks, and at December 31 our subsidiary, Mid-Illinois, had $94 million of bank loans outstanding.

During the year we reacquired $11 million principal amount of sinking fund debentures. At year end, our capitalization was 56 percent bonds and debentures, 6 percent convertible preferred stock and 38 percent common stock equity.

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Food, clothes and exercise are three staples of human life. Electricity helps process coffee cakes at the Kitchens of Sara Lee, show merchandise to its best advantage at Goldblatt's, and light and heat the gym at Hampton Park's all-electric junior high school.

The Midwest's refiner
The Chicago area has struck oil. Northern Illinois within five years may well become the refinery center of the Midwest. Most of the refineries are or will be located southwest of Chicago along the Illinois Waterway. The Union Oil plant at Lemont will use electricity to drive its huge 19 thousand horsepower centrifugal blower. Our salesmen helped to convince Union's management that an electric motor served from our lines is more economic than the steam-driven turbine traditional in oil refineries.

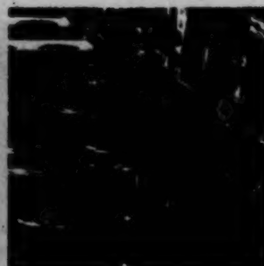
Three other large motors totaling another 20 thousand horsepower also went our way. The new Lemont refinery will be one of the most electrified in the world. It will have a demand of 70 thousand kilowatts and run at 95 percent load factor. Another oil company is now doing site work for a refinery even larger than Union's.

Chemical processors are first cousins to refineries and often locate near them. A number of such plants are in operation or building in our service area. They join a giant, the Northern Petrochemical complex, being developed in three stages over the next several years.

$10 million from giants
Northern Petrochemical and Union Oil, when completed, will contribute close to $10 million to our annual revenues. If fully operative today, these giants would rank third and fourth among our large customers.

Completion of new oil pipelines from Canada and the Gulf Coast to our area coupled with the market advantages of a northern Illinois address have led to this sudden blooming of massive new electrical loads.

An Edison lineman puts his finishing touches on transformers added to serve the expanding power requirements of people. The vitality of our area's commerce and the quality of its goods are shown by pictures of Chicago's Board of Trade and of a gleaming row of electric ranges.



Wages up 6%, benefits higher
As a result of union agreements signed last spring, hourly wage rates increased an average of 6.2 percent. Pensions, insurance and other fringe benefits added the equivalent of another 6.4 percent to payroll. These increases amount to about $12 million on an annual basis. Wages have been renegotiated each year. Fringe benefits, however, had not been negotiated for five years, and the increase in benefits should be looked at in this light.

At December 31, 1969 we had just under 14 thousand employes, an increase of 167 over the same date a year earlier.

181 thousand stockholders
At year end, we had 181 thousand stockholders, down about 2 thousand from a year ago. The slight decrease probably is due to expansion by institutions of their holdings of Edison stock. There were 169 thousand holders of 42 million common shares. In addition, 12 thousand stockholders owned over 4 million shares of our convertible preferred stock.

About 120 thousand shares of common were acquired by employes during 1969 under the stock purchase plan, and 43 percent of Edison's employes were in the plan at December 31.

Board and management changes
At the 1969 Annual Meeting last May, Joseph S. Wright was elected a Director of Commonwealth Edison. Mr. Wright is Chairman of the Board of Zenith Radio Corporation. At year end, John L. Gordon, Chairman of the Board of the Central Illinois Electric and Gas Co. Division, retired from active service.

During the year, Wallace B. Behnke, Jr. was elected a Vice-President, Byron Lee, Jr. was named Assistant to the President, George P. Rifakes, was appointed Manager of Fuel, and Charles G. Harnach was promoted to Division Vice-President of our Southern Division.

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The future of our whole metropolitan world depends upon children such as this. It is Commonwealth Edison's role to furnish clean, reliable, plentiful and economic electric power to him and to eight million others in the '70's.

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Commonwealth Edison Company

72 West Adams Street • Chicago, Illinois 60690

January 17, 1969

Dear Security Analyst or Fund Manager:

Each new technology has ushered up its own skeptical and detracting opposition.

The Wright brothers succeeded despite those who pointed out Icarus' fatal plunge to prominence. Battleship admirals scoffed at air power until the Repulse and Prince of Wales went down. Dutch workers tried throwing their shoes - sabots - into newly invented weaving looms and thus were responsible for coining the word sabotage. And one even can imagine manuscript illuminators writing letters of complaint to Gutenberg.

Similar opposition may be gathering against nuclear power, with tales of spiraling capital costs, uranium shortages, atomic bombs, late-delivery brownouts, and so on.

Though the critics are wrong, there's a little fire in their smoke. Take Commonwealth Edison. We have reactor vessel delivery delays. Though no technical problems are involved, Dresden 2 will be eight months late and the two nuclear units following it probably will be several months behind schedule. Despite this, consider the handsome payoff ahead from nuclear power for Commonwealth Edison.

- We have over 5000 Mw of nuclear capacity in six units under construction. We got our four 809 Mw units at an average of $118 a kilowatt. Turnkey contracts, no escalation. Our other two units will cost a third to a half more, depending on how future construction costs go.

- We've contracted for 10 years worth of fuel fabrication at good prices for our six reactors. We've bought all the yellow cake we'll need through 1975, much of it at below $6 a pound.

- By 1974, about half our kilowatthours will be coming from nuclear machines at fuel costs below two mills, including all carrying charges on the fuel inventories. Present system fuel costs average 2.7 mills, and we figure our newest coal-fired units at 2.2 mills.

We could go on and on. Air pollution? We beat the rush two years ago when we volunteered to the City of Chicago to cut SO_2 emissions in half within a few years -- mainly because of nuclear power. Future cost protection? Coal, with a whopping recent eight percent wage settlement, is not going any place but up. But nuclear fuel is mostly a manufactured product, and stands a good chance of price reduction through technological improvement.

We hope you'll understand why we're glad to be the leading nuclear company.

Though medical opinion differs, our experience is that the flu already has passed its peak in Chicago. Why not dodge it and pay us a visit? If you can't make it, give us a call if we can be helpful.

Sincerely,

Preston Kavanagh

Preston Kavanagh
Assistant Secretary

312-RA6-1200
Ext. 2122

Commonwealth Edison Company

ONE FIRST NATIONAL PLAZA ★ CHICAGO, ILLINOIS

Address Reply to:

POST OFFICE BOX 767 ★ CHICAGO, ILLINOIS 60690

December 4, 1969

Dear Security Analyst or Fund Director:

Electric power plants these days are being billed as the worst things since the Krakatoa eruption or Vesuvius' burial of Pompeii. Until a few months ago, Commonwealth Edison had been spared the partly-informed public clamor about pollution which has marked so much of the country. Now, however, things are heating up a bit and we thought you'd like to know our situation.

In summary, we have an early start, some fixing up ahead, and a future program -- thanks mainly to nuclear power -- ranking with the country's best. In detail:

* We're responsible for something over 10% of high level and considerably less of ground level pollution in metropolitan Chicago. Our emissions are mainly sulfur dioxide gas.

* Three years ago we submitted a program to cut coal burn in our six Chicago-area stations in half by 1975. Mayor Daley praised the program as "the first of its kind in the nation" and "an example of what local industry can do".

* A Chicago ordinance effective next July requires that the sulfur content of coal be lowered in progressive steps through 1974. The ordinance allows us to fulfill its objectives by burning less rather than lower sulfur coal. We'll meet that timetable and have applied for the appropriate approval.

* By mid-1973 nuclear plants will be turning out 40% of our kilowatthours.

* Ten years ago we had 58 coal-fired boilers at city stations; today it's 12. We're replacing old peakers with gas turbines, and burning all the gas we can get in the remaining base-load boilers.

* We'll spend $25 million between now and early 1973 for improved or brand new dust collecting precipitators, bag filters, and the like at 11 stations.

* In all, we've earmarked $70 million of our five-year capital budget for pollution control facilities.

* We see no problem in radioactive emissions from nuclear plants. The AEC's standards are stringent, and we shall continue to be well below them. For example, the Jet Set New York analyst making just one round-trip flight to the coast gets more radioactivity than the very closest neighbor of a nuclear plant.

* We're not in hot water on thermal pollution. Lake Michigan is huge and cold, and our lake stations have done and will do it absolutely no damage. For our big new river units man-made cooling lakes are generally necessary.

* We've run ads, developed a squad of personable experts, been on TV and radio, and accepted every speaking date we can arrange to tell our clean air and water story.

* Our billion dollar investment in nuclear (5,200,000 Kw), minemouth (1,200,000 Kw), and gas turbine (1,600,000 Kw) generation is good power system economics. It also advances our clean air cause. These are golden words.

* The Illinois Attorney General intervened in our rate case on the pollution issue. Now the Governor has requested Commerce Commission hearings for <u>all</u> electric and gas utilities to see how the problem can be overcome. This will provide a fairminded and orderly forum to get the facts before our public, and could remove that issue from our rate hearings.

We've been directed (like Isaiah) to write so those who run may read, and thus we blush at three instead of two pages. Explaining pollution, however, is a complex thing and so is doing our full share to throttle it. We hope you'll agree Commonwealth is ahead of its times. And that we are determined -- insofar as we can accomplish it -- that northern Illinois shall have pure water and clean air.

Sincerely,

Preston Kavanagh

Preston Kavanagh
Assistant Secretary
312/294-3173

Defendant's Exhibit 93

NUCLEONICS WEEK — April 4, 1968

COMMONWEALTH EDISON: PROFILE OF NO. 1

Bootstrapping Its Way To Nuclear Know-How

(First of a series)

Commonwealth Edison takes very matter-of-factly its huge commitment to nuclear energy, the largest of any non-nationalized utility in the world. Some smaller companies may look with awe upon the atom and wonder about its role for them, and the risks lurking therein. Edison views it as just another in the series of technological breakthroughs that have marked the growth of the utility industry—a breakthrough of which the company was ready to take advantage. But let them tell it, as they did in an interview with Nucleonics Week editor Roger Newburger. The Edison cast: J. Harris Ward, chairman and chief executive officer, who alternately joined in at the conference table and sprang up to point to a map or chart on the wall; Gordon R. Corey, chairman of the Finance Committee, and Wallace B. Behnke, Jr., assistant to the president. Most of what follows is in their own words, although edited and reassembled for reasons of space and continuity. For this reason, and because the dialogue was intended to give a picture of the whole company, no attempt is made to identify the speaker of each phrase.

When we made the decision to go nuclear with Dresden-1, back in 1955 (they said), it was mostly due to Willis Gale's farsightedness. He was our chairman then. He felt that this was the most exciting possibility for the next technological breakthrough in the electric-production end of the utility business, and it has turned out to be just that, so far. Nuclear energy offered the solution to several basic problems that we could see on the horizon. Back in the early 1950s, we could see that the logistics of fueling the coal-fired generating capacity needed by 1980 or 1990 would be a problem. We also could see

back then that air pollution, particularly in our metropolitan areas, would be a problem. To us, it appeared that nuclear power might answer such basic, long-term questions. This was well before anyone had a handle on the economics.

In 1951, we were selected by the AEC as one of the four original study teams to explore the possibilities of using the atom for power generation. Our young engineers, along with those of other companies in our research group, worked on it, designed a lot of reactors, worked closely with AEC, fumbled through all those early days while we were learning and getting ourselves tuned up and educated as to what it was all about.

OPTIONS IN CONSTRUCTION MANAGEMENT

Says Commonwealth Edison: Since Westinghouse and General Electric quit the turnkey business, we have found some advantages in having a little more control over construction schedules. But we weren't especially eager for them to get out of it, for turnkey provided another option to us in seeking every possible way of buying the lowest-cost and best unit. . . We're not at all afraid of handling the construction chores ourselves. One key there is knowledge of local labor and we think we have more know-how in this area than GE and Westinghouse—although they have a lot more know-how now than they used to have.

AEC people are sophisticated, conscientious, capable regulators, Commonwealth Edison feels. These are the company's views: They don't do all the things we'd like to have them do, but on some things they listen to us. . . Rather than getting more difficult, it is becoming somewhat easier because we are understanding each other better. These are difficult times for both the regulated and the regulators because of the rapidly changing technology, but we're growing up together in this business. AEC works very

hard at it and we do, too. . . This matter of questions by the ACRS and AEC regulatory staff on the preliminary safety analysis is very time consuming and is one of the big problems power companies have. We try to keep in touch with the letters and questions to other companies through our contacts in the industry and with manufacturers. As time passes, we hope we will be able to solve our joint problems faster and more effectively than we have to date.

Everyone knows when the plutonium glut is going to hit, and it's obvious that this fuel will have to be recycled in water reactors, says Commonwealth Edison. But it also thinks: There is no need to develop for use in 1975 the super-plutonium fuel of 1985. . . The nation can't afford the luxury of redundant research. . . We need some patience and a fairly conservative first-round development effort to get this into the competitive fuel economy. It is important that the independent fuel suppliers have a position here at the earliest practical date but too soon will be too expensive. . . Certainly, they would like to have the utilities pay for all the research and a large portion of the fabrication facilities but we have to worry about cost to the consumer, too. . . Plutonium fuel is not a new subject; only its commercial application is. We must find out what has to be done and who will do it, then get it off to an early competitive start and let the perfect plutonium fuel be developed with the passage of time.

Over and over again, we emphasized to our managers and engineers and accountants our belief in the cost-price-sales-earnings spiral: reductions in costs keep the price of electricity going down; this leads to increased sales, which make it possible to take advantage of economies of scale; this, in turn, brings additional cost reductions and rate reductions and increased earnings. Now, we don't say that we're seers, but because of this

philosophy we're anxious to take advantage of every new wrinkle that comes along.

When it came to Dresden-2, we saw the advantages from an air-pollution standpoint, but we were particularly pleased—and just at first a little surprised—when we saw nuclear prices coming into the ball park where they could beat even our new fossil-fuel plants supplied by unit trains. Just one year before we ordered Dresden-2, in February of '65, we had put into operation the largest unit train in the world, and it was going to cut the price of bringing coal from southern Illinois to Chicago from \$2.56/ton to \$1.30/ton. We thought this was a terrific breakthrough for coal, but then we saw Dresden-2 coming in still cheaper. Once we had made the decision to go nuclear there, Dresden-3 and Quad Cities and the Zion units followed along naturally. Then we saw more and more the potential advantages in the air-pollution field and the possibility, as metropolitan siting becomes acceptable, of getting our stations closer to load centers, thus helping alleviate—both in cost and appearance—the problem of cross-country transmission lines.

(In 1973), when Zion-2 is scheduled to begin operating, about 50% of Edison's output will be nuclear-generated. Is the company worried about such a vast commitment to the new technology, with plants of an untested size?)

We think the possibility of nuclear power stations not working is almost non-existent. The technology is well proven. Certainly we have worries about getting them built on time and keeping them running, but we have these with every plant. For instance, when our Ridgeland-1 was built it introduced a certain kind of stainless-steel piping which was a great advance back in 1951. Soon after it went into operation, cracks developed in the stainless steel. We had to tear out sections of it and had all kinds of examinations made of the piping. We never have gone back to stainless of that particular kind. For another thing, apparently nobody yet knows how to build a boiler tube, they're always springing leaks, and boiler availability is our biggest problem with our modern coal-

fired units. These boilers are 22 stories high, and when you develop a pin-hole leak in one you shut the whole thing down and, after an eight-hour cool-off, you send up a man in an asbestos suit in a bo'sun's chair to fix it. It's a perpetual problem. Maybe there's a little more risk with nuclear hardware, but we've been making and using turbines and condensate pumps and fans for years and they're certainly not new parts. Even though we haven't been making reactors for years, we did start studying them in 1951. Four years later, we ordered Dresden-1 for service in 1960. Then we played with Dresden-1 for almost five years before ordering Dresden-2. So you see, the idea of a reactor is not very new.

Then, as you get into the 1970s, you'll see an increase in regional interconnections between large power systems and a decrease in the number of weak spots in these systems. And you'll know where the weak spots are, the difficulties with them. Sometimes you'll have to build a line and sometimes you'll have to persuade the other man to build a line. Now, when we put a nuclear station out there at Quad Cities, we establish a joint-ownership relationship with the utility to the west and we are all part of the 345-kv loop around the Middle West. If we have trouble with the plant, various interconnected companies will make up the lost capacity. So, as you increase in strength and interconnections, the vulnerability of any single system to the loss of an individual plant becomes a matter of less concern.

These 1,000-Mwe plants are not so strange, anyway. They're a little bigger, but not very much bigger even in terms of physical dimensions. Go back to Dresden-1 and its 200 Mwe. What was the Vallocitos Boiling Water Reactor? 5 Mwe? There was an extrapolation of about 20 to 1, and we made it all right. This has been true all the way through the power business. Not so long ago, we were building 150-Mwe fossil units, then moved to 300s, then 600s. It's a matter of degree. And General Electric and Westinghouse are competent designers and manufacturers, and they have a lot riding on these machines, too.

NEXT WEEK: Limitations on mine-mouth plants; future siting; thermal effects.

NUCLEONICS WEEK—April 11, 1963

COMMONWEALTH EDISON: PROFILE OF NO. 1

NUCLEAR COSTS ARE RISING, BUT THERE'S NO CEILING ON COAL, EITHER

(Second of a series)

Like other utilities, Commonwealth Edison maintains a running comparison of nuclear and fossil-fueled power-production costs. In recent years, Edison's comparisons have led to the Dresden, Quad Cities and Zion nuclear units. Despite recent sharp price rises for nuclear-plant components, the company sees little coal in its future. Three executives tell why in an interview with NUCLEONICS WEEK *.

Sometimes (they said) we have to remind people that Dresden-1 was ordered in 1955 and went into service in '60; it's been running a little over seven years but the first full equilibrium core loading of fuel won't be burned up until sometime in the early '70s. We have our estimates, of course, but there are a lot of imponderables in trying to compare costs, particularly when it comes to estimates of future escalation. We think the construction costs of nuclear plants are going to be affected by escalation of construction labor and things like that; Zion won't go into service until 1972 and '73 and we won't know until it gets built how much that escalation has amounted to. In addition, future fuel costs are an equally important factor because they will total more than the plant cost over the life of the unit. But, despite escalating

[Pictures]

* The three executives are J. Harris Ward, Commonwealth Edison chairman; Gordon R. Corey, chairman of the Finance Committee, and Wallace B. Behnke Jr., assistant to the president. They discussed the company's philosophy and management techniques with NUCLEONICS WEEK assistant editor Roger Newburger. This second of a three-part series again is mostly in their own words and, so as not to interrupt the flow, identification of the specific speaker is omitted.

plant costs, we feel that escalation of coal costs over the life of a competing coal-fired plant would be at least as great as it will be for nuclear fuel. That could be 35 years—say 1973-2008—and who can say what the price of mining coal in Illinois is going to be in the year 2008?

You cannot buy coal now for such a plant without buying it on virtually a cost-plus basis. Our policy is to buy it on 5-10 year contracts. Coal is not a great big capital investment business; about all you do when you buy it is pay what it costs a man to get it out of the ground. We believe we can do better buying it, not from year to year, but in 5- or 10-year intervals. That way, we can buy from the most efficient miners—the ones who have the best people and are doing the best job at any given time. If we were to pick out one company and say; "We are going to give you a long contract," obviously he'll retort, "Well, I'll give you the best price I can, but I have to have escalation," and then you end up with cost-plus.

Partly as a result of air pollution, partly because of urban congestion, there has been a trend to mine-mouth generating stations. We put one in, too—the first unit went into service last May. A few years ago, we couldn't have done this, but then 345-kv technology came along. We needed additional tie lines to the south for the expanding interconnections and we had to put at least one of those lines through the mine area anyway. When we gave the mine-mouth the benefit of this transmission in figuring costs we were able to prove it in economically, so we thought we might as well use the line as an equivalent to shipping coal from central Illinois to Chicago. Probably similar situations have brought about the mine-mouth plants in the East. The expanding transmission grid made lines available anyway and you didn't have to figure that as part of the station cost.

But once you get a mine-mouth plant, you absolutely have to contract for coal to supply it. The capital cost on the plant is $120-million, but the capital cost on the mine is about $10-million. Obviously, you can't be put in a position where the $10-million investor can hold you up because you have your big $120-million plant

sitting beside his mine; so, for all practical purposes, you have to buy the mine. That is the situation with out mine-mouth plant: we made a long-term cost-plus contract for the coal, it runs to 1982 with three 10-year renewal options that will take up to the year 2012. The need to protect your investment in a mine-mouth plant may give a false impression that longer-term coal contracts result from the competition with nuclear fuel.

Of course, on any coal-fired plant we are concerned about air-pollution, just as we are concerned about thermal effects on cooling water of both our nuclear and fossil plants. Neither of these ideas is exactly new around here; we've been thinking about them for some time, and we try to plan to avoid problems. We're fortunate in the availability of water in our 11,000-square-mile service area and we try to be foresighted about our use of that water.

We're not yet hurting for sites for future plants: we have several more river locations available and Lake Michigan provides a vast amount of water. In theory, if it weren't for transmission problems, we could expand lake-front stations, such as Zion, indefinitely, subject of course to environmental effects. But the metropolitan area is so built up, especially with heavy industry, that we can't put through too many transmission lines. While we can take a million kw on our line from the East—maybe even a little bit more—we're limited by the risk that one airplane or one tornado conceivably could knock out both these circuits. When you have a big generating station you like to have at least two ways of moving the electricity, and you prefer to move it at pretty high voltages. That's very hard to do through the center of a town because of the electrical losses inherent in going underground with a 345-kv line. The cost is prohibitive, too.

ON FUEL DIGGING AND DESIGNING

Commonwealth Edison says: We have been thinking for six or seven years of the possibility of getting into uranium exploration. We probably shouldn't be in it unless others are not

doing the job right. . . We had feared some shortage of uranium in the early 1970s but the situation seems to have eased. We have committed for over $100 million worth of yellowcake at good prices and we're not nervous about our supplies. . . We're not interested in leasing fuel. We can get money as cheaply as anyone else and we're inclined to do our own financing. . . We lean in the direction of providing our own fuel design; we want to understand the fuel world completely. Also, we fully expect to manage our own nuclear fuel while it's in the reactor, rather than what we do now, on the services of the fuel suppliers.

There are advantages to everyone in having plants reasonably close to load centers but we're not pushing this too hard. Dresden is not too far from Joliet, but that's not the same as being near the Oranges or Newark, in New Jersey; it's a relatively isolated spot. The plant was quite well received, too. After all; Chicago was the birthplace of nuclear power, and Argonne National Lab, where the boiling water reactor was conceived, is not far from Joliet. It was only logical that our first nuclear plant should be built nearby. Moreover, with the property taxes that we pay on Dresden, the community was able to fix up its schools and make other needed improvements. The people were genuinely happy to welcome Dresden station.

When time came for another station the people of Zion were inclined to take it for granted that it would be located there on land we had owned for over 10 years. When word leaked out that we were considering a demonstrate site near Seneca, Zion got pretty upset, thinking about all that tax money with which it could build schools and parks and other things a community likes to have. And the people in Seneca began to think about it, too: that maybe it would be a lot better than having a fossil-fuel plant or an industry throwing out a lot of smoke. They wound up with a spirit of competition, all on the positive side. No one in this area

has picked up any of the negative feeling that existed elsewhere in the country. There are some conservationists here concerned right now with preservation of the natural prairie that we have in Illinois, but there is no conflict with Dresden and we believe our relationship with them is friendly.

There's been a lot of talk about building an airport for Chicago about five miles out on Lake Michigan and, if they ever did it, perhaps it might make a good deal of sense for us to have a generating plant there, too. But this is still pretty much in the realm of conjecture. We have no problem of overheating lake water, since we will be well within the temperature limits, and even on the inland streams we haven't had to go to cooling towers for any of our plants. We've tried to plan very carefully to build them far enough apart to give river water adequate time to cool between plants so we can stay within the regulations. We still have a number of potential sites and room for added capacity at existing stations. We may have to go to cooling towers some day, but not yet.

We think, also, that technology is helping, not hurting us. We're building 1,000-Mwe nuclear stations that will heat the water to a certain temperature. Hopefully, 30 years from now, they will be replaced by 2,000-Mwe stations that won't heat the water any more than the 1,000-Mwe stations did. This happened in the coal side of the business and it's bound to happen in the nuclear side, too. We moved to higher and higher steam temperatures in the coal-fired boilers and yet maintained the same temperature in the condenser. Right now, the low cost of nuclear fuel doesn't lend itself economically to the use of plants with high steam temperatures and pressures and correspondingly more efficient turbines. Steam superheat, for instance, just disappeared because, economically, it didn't have a place. But we're speculating that this may no longer be true with the advanced breeder technology that we'll have in the 1980s.

NEXT WEEK: It's no business for midgets; joint ventures; personnel development.

NUCLEONICS WEEK — April 18, 1968

COMMONWEALTH EDISON: PROFILE OF NO. 1

NUCLEAR POWER IS NOT A SMALL-COMPANY BUSINESS

(Third of a series)

Commonwealth Edison is a giant and it minces no words in stating its feeling that this benefits the public. The power-generation business is not meant for midgets, said three executives in an interview with NUCLEONICS WEEK *.

Edison is now the single descendant of well over 200 power companies, but back in 1938 the various consolidations to that time had resulted in five separate companies (the three executives explained). It was about that time that the five began to be operated as a single system, thus permitting better over-all planning. When an area is covered by many small companies you'll have one company planning to put a plant here, another company thinking of a new unit there, with resultant lack of cohesion. In New England, for instance, the companies have gotten together now but, although they were thinking 15-20 years ago about this kind of over-all planning, the will to achieve it had to overcome normal inertia and this cost them a great deal of time. Some might think this kind of talk sounds monopolistic, but we think it's for the good of the public.

What happens to the little companies in this day of big nuclear plants? We're not sure that there is a single

[Pictures]

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* The three executives are J. Harris Ward, Commonwealth Edison chairman; Gordon R. Corey, chairman of the Finance Committee, and Wallace B. Behnke Jr., assistant to the president. They discussed the company's philosophy and management techniques with NUCLEONICS WEEK assistant editor Roger Newburger. This last of a three-part series again is mostly in their own words and, so as not to interrupt the flow, identification of the specific speaker is omitted.

solution for every situation. We had such a problem in our territory a little over a year ago. Rockford, the second largest city in Illinois, was virtually surrounded by our system—an island in our service area served by Central Illinois Electric & Gas—and that company opened discussions with us on power supply and nuclear units. We both recognized the solution, and a merger that would best serve the interest of both companies' customers and stockholders was relatively easily accomplished.

There are other situations and other solutions. In our territory, there are seven municipalities with their own power distribution departments. Two generate their own electricity. We supply the others at wholesale rates which are under the jurisdiction of the Illinois Commerce Commission and the Federal Power Commission. We think the regulatory commissions are perfectly capable of looking after the well-being of these municipalities. After all, each of these towns that we serve is a smaller user of electricity than some of our large industrial customers; no one hears any of the industrial customers asking for a share of one of our nuclear plants and we seek no justification for a municipality to seek such a share, or a voice in running the plant, either.

The industry may seem to be evolving in a direction which favors one kind of company more than another, but we think it desirable to have utility systems large enough to take advantage of the economies of size made available by today's technology. This means large enough—on the order of 10,000 Mwe—to buy and use a 1,000-Mwe unit. Maybe tomorrow will bring some other technological development which will indicate a different size of system. Two things, though, seem quite clear: little generators are a very expensive luxury, and atomization of the industry, so as to give every little company a chance to own a small piece of a reactor, would create a difficult situation. We can just imagine a nuclear plant with some people having a 1% ownership and a 1% vote and somebody else having a 3% share and a 3% vote, and every time you wanted to buy some yellowcake you'd get all the voters together to see if they could agree on the purchase.

The writing a few years ago of the National Power Survey demonstrated that public and private power people can work together. One of us was involved in that, along with a man from TVA and the FPC staff. We found that philosophically, as far as operations and objectives were concerned, we were not far apart. It seems unfortunate, therefore, to reinject this old question of public power vs. private power into the matter of nuclear plants. TVA is building power stations and distributing power and selling it to municipalities, and their municipal customers aren't saying, "Please give us a piece of Browns Ferry."

Municipal systems should be given the benefits of large-scale economies, but they can have these by becoming customers of the big systems. It is not a small-company business. Perhaps some would say that this is against America's basic philosophy and that anyone should be able to take a crack at anything. But that's like saying anybody can get into the automobile business. It just isn't true. This country has passed the point where you can economically build a car in your barn. Small systems will continue to operate and small plants may occasionally be competitive because of geographic isolation or special tax or governing-financing privileges, but in any wider view construction of small generating units seems wasteful. There are advantages in being small, but bringing uneconomic generating units on line is certainly not one of them.

ON BREEDERS AND CONVERTERS

The r-&-d effort on fast breeders is proceeding at an adequate pace, Commonwealth Edison thinks. It explains: U.S. timing may lag a little behind England's but we have different economic concepts and different objectives. They don't look upon capital costs the way we do and they have an obvious interest in minimizing their dependence upon uranium supplies from the outside world. . . Our breeder studies with General Electric and Westinghouse should bring

us in two years to the point of decision on building a demonstration plant, then about five years more for construction and operation. If the breeder comes in on this schedule, there probably would be no room for the advanced converter, especially if light-water reactors continue to improve. However, we don't rule out the possibility of the converter and we continue to watch all these technologies.

Collective plant ownership is a possibility, but the partners should not be too different in size. When we negotiated the Quad Cities agreement with our neighbor, Iowa-Illinois G&E, it was arranged that we would manage it for the good of both parties. This was a fairly simple approach, but even this partnership can never be quite as efficient as single ownership. For instance, if yellowcake is purchased at various times and prices for both Quad Cities and other Edison plants, what is the price to be charged to Iowa-Illinois? Only goodwill and mutual trust between us have enabled us to solve such problems. Our management of Quad Cities does not relieve us of any legal liability to be fair; in fact, it puts the monkey on our back. But at least there is no committee management, which we believe is ineffective, inefficient and cumbersome.

Our management philosophy is toward decentralization. We are split into seven geographical divisions, each with a vice president who, in effect, is running his own sizable utility company. Some of these divisions have $100-120-million a year volume and 400-500,000 customers. We move people around among divisions, make them profit-conscious, cost-conscious. We show them what other divisions are doing. Since we have adopted this approach, all the divisions have improved in performance. This is what competition does.

Another effect of competition is that it encourages young men to want and accept responsibility. Some of our divisional vice presidents now are under 40 years of age. Our structure lends itself to similar treatment of other personnel. We can and do move bright young

engineers into the nuclear field, bright financial people into nuclear purchasing and nuclear analysis. We're constantly training and developing our people, sending them off to school, to national labs, to Dresden station, to Purdue University for the fuel-management course we've helped sponsor. When we hire we're interested in a man's study discipline, but not exclusively.

When we first got into nuclear matters we started with just a few young electrical and mechanical engineers, a chemist, an accountant. Cliff Zitek was a chemist; we got him into Argonne National Lab for training in the early days. We had Murray Joslin then, and the late Titus LeClair, both electrical engineers, and they set about learning the business. You need only a few highly competent people with specialized disciplines who can help you with some of your thinking and development.

The Dresden station has been our keystone: the young engineers worked along on its development, put it into service and operated it. We have worked hard to put as many people through that station as we could so that today we have a fairly sizable and extremely capable staff with a wealth of experience. A lot of these young men who started at Dresden have gone on to become supervisors and managers in our engineering area. The fellow who buys our nuclear fuel trained at Dresden; so did another man, who then worked in our engineering department, designed for awhile and now is stationed at Westinghouse studying fast-breeder technology. We have another engineer at General Electric in breeder work, and there's one at the National Reactor Testing Station, working on EBR-2. We will bootstrap our way to the fast breeder just as we did in light-water reactors. You don't have to start with a whole platoon of specialists in each discipline. Our people are learning the language and the technology. They may not have their hands on all the subjects yet, but they'll be educated by the time we'll have to decide if we want to build a breeder.

We would like to see universities turning out more nuclear specialists; an education in nuclear engineering is important to power companies. But specialized formal education isn't the whole story. Put a man at the Dresden

station for six years and he soaks up an amazing amount of knowledge. He may not design the first fast breeder, but he'll certainly know how to operate a boiling water reactor. This is technical work of a repetitive nature, and it represents good jobs which don't need to be filled with graduate engineers or physicists. You look back 10 or 20 years and we had engineers doing a lot of things then that technicians do today. The important thing—for both technicians and management people—is to give them the opportunity and incentive for development. We think we offer as much of these as anyone in the business.

DX 94 Commonwealth Edison Company
Annual Report 1968

* * *

Do saxophones sound better in all-electric schools? We think so. These students at Hampton Park's West View Junior High School seem to like their environment. Education is a fast growing part of the nation's economy, and because of northern Illinois' high income and education levels, new school construction is especially strong in our area. We have taken advantage of this by promoting over three million square feet of all-electric schoolroom space.

and other operations. Of the electric payroll, 72.5 percent was charged to operating expenses.

Depreciation on electric plant in 1968 was $94,020,351, equaling 3.30 percent of depreciable property. This was up slightly from 3.29 percent for 1967. Commonwealth Edison uses one of the highest depreciation rates in the electric power industry. Technological change is rapid, and we take advantage of this by purchasing the most modern machines and equipment. Also, we think it prudent to make adequate provision now for possible future obsolescence.

Taxes Up Over Eight Percent

In 1968 we provided $202,310,655 of local, state and federal taxes for our electric operations. This is equal to $81 for every customer on our lines. This year we provided 8.6 percent more for taxes than in 1967, and state and local taxes once again had the largest portion of the increase. We try to manage the affairs of the Company to maximize operating economies and then to pass these savings along to our customers and stockholders. Rising costs and especially rising tax costs are major offsets to the economies we are able to achieve.

Our electric tax provisions were:

	1968	1967	Percent Increase
State and local taxes	$101,287,392	$ 90,982,961	11.3
Federal income taxes	85,640,000	83,009,000	3.2
Deferred federal income taxes (net)	11,947,108	9,302,000	28.4
Social security and miscellaneous federal taxes	3,436,155	2,957,374	16.2
	$202,310,655	$186,251,335	8.6

Record Summer Load

A record peak load of 8,950,000 kilowatts was set between 1 and 2 p.m. on August 23, a hot, humid Friday afternoon. This is 1,307,000 kilowatts or a remarkable 17 percent higher than 1967's summer peak. While 1968 had normally warm summer temperatures, the prior year was one of the coolest in 50 years. In effect, 1968's peak reflected the heat sensitive load growth of almost two years.

Interconnections

Reliability of our service is enhanced by the Midwest's network of high voltage interconnections. In May, tornadoes destroyed or damaged 84 towers on two different 345,000 volt lines, spaced four miles apart, and leading from our Kincaid Station. Because of our interconnections, there was no interruption of service to our customers.

New Generating Units

In June, a 600,000 kilowatt twin to the unit brought on line in 1967 was placed in service at our Kincaid Station. The two-unit plant in central Illinois is located virtually on top of the country's largest deep coal mine. Instead of bringing coal to the generating plant, the generating plant has been brought to the coal. Though Kincaid Station is far from any urban area, $6,000,000 has been spent at the plant for air pollution control facilities.

During 1968 we ordered a coal-fired unit to be located at our existing Powerton Station near Pekin, Illinois. It will have a capacity of 840,000 kilowatts and is scheduled for completion in the spring of 1972.

We decided on the Powerton addition because of the strong growth of our peak loads and because coal-fired units can be built more rapidly than nuclear units. While

* * *

Farmer John Moran dries corn on a 500 acre all-electric grain farm near Manteno. He estimates his drying expense at under 4¢ a bushel using electrically driven fans and duct heaters, about half the operating cost of his former system. Mr. Moran, chosen in 1967 as Illinois' Outstanding Grain Producer, will use a total of about 130,000 kilowatthours this year. We serve seven million farm acres in a territory containing some of the Midwest's richest soil.

this decision was taken primarily because of accelerating load growth, it also will give us protection against delays in delivery of our nuclear units.

Dresden 1, a 200,000 kilowatt nuclear unit, has been running well since it came on our system in 1960. In addition, we have six more nuclear units under construction.

Dresden 2, the first of the six, is an 809,000 kilowatt nuclear generating unit being built under turnkey contract by the General Electric Company. While the unit should begin producing kilowatthours in the fall of 1969, full commercial operation is not expected until the turn of the year. When we ordered the machine four years ago, we planned to have it ready for the 1969 summer peak.

The delay has been due to start-up problems in a subcontractor's plant built to fabricate reactor vessels. The reactor vessel makes up only about five percent of the total cost of a nuclear unit, but its timely delivery to the construction site is essential to on-schedule completion of the unit. Though the reactor vessel fabrication bottleneck appears on its way to being broken, we still expect delays of several months for the next two nuclear units coming on line after Dresden 2.

Nuclear Savings

Despite these delays, we are glad to be the nation's leading nuclear power company. This leadership has enabled us to assemble and retain an outstanding staff of young nuclear scientists and engineers. Also, because we were early in the field, we were able to buy nuclear fuel and generating units at low prices with limited exposure to escalation.

Four of our six nuclear units on order were purchased on firm price, turnkey contracts for an average of $118 per kilowatt, including all overheads. The two others, at our Zion Station, are expected to cost a third to a half more, depending on future construction costs. In all, these six nuclear units have a total capacity of over 5,000,000 kilowatts at prices which look more and more attractive in the light of today's market.

In addition to providing low cost capacity, our nuclear units will be powered with economical fuel for which contracts already have been signed. We have purchased ten years worth of fuel with a very limited exposure to price escalation. All in all, we estimate that by 1974 our nuclear units will be saving us $10 million a year in capital and operating costs, compared with coal-fired units of the same vintage.

Capacity Growth

On order for 1969 and 1970 delivery are 727,000 kilowatts of fast-start peaking units. These will join the 664,000 kilowatts of similar capacity installed during 1968. These machines have low capital costs—about $90 per kilowatt—but relatively high fuel costs. They can be built quickly and because they require no cooling water, the units can be located near our load centers, thus cutting transmission investment.

We shall depend upon our big nuclear and coal-fired units to meet our base loads, using the peaking units for a relatively small number of hours each year to meet seasonal peaks and unexpected outages in the larger units. Because the turbines are small and can be started quickly, they can be brought on line in small increments as our load rises.

Capacity additions are carefully planned to serve the rapid load growth in our service area. An illustration of the strength of this growth is that five years ago we had 6,762,000 kilowatts of net generating capability. Today that figure is 9,757,000. And five years hence, after new units have been added and older equipment retired, our net generating capability will total about 15,800,000 kilowatts.

* * *

DEFENDANT'S EXHIBIT 95

Edison seeks A-site Downstate

By Harlan Draeger

Commonwealth Edison Co. said Tuesday that it is seeking options on about 7,000 acres of land in La Salle County as a possible site for a nuclear power plant.

The land is located near Seneca, 60 miles southwest of Chicago's Loop and not far from the company's Dresden nuclear plant.

"We have no commitment to build anything out there," an Edison spokesman said. "We do have agents trying to obtain options."

HE SAID present expansion plans are expected to meet generating needs through 1975.

"We will need additional capacity in 1976," the spokesman said, "but where or what it will be has not been determined. It is a possibility that there could be a plant in this general vicinity."

The spokesman said that, if a plant is built near Seneca, it is likely to be a nuclear generating station. "We're fairly well committed to a nuclear future," he said.

FIRST REPORTS that Edison was trying to line up land options near Seneca came from real estate agents in La Salle County.

Edison officials said that any big new plant would require water cooling facilities, probably a pond.

COMMONWEALTH Edison opened its Dresden nuclear power station near Morris in 1960. The second Dresden unit now is being tested for a start-up this spring. A third unit will go into operation next year.

Two nuclear units also are being opened at Zion and in the Quad Cities area.

By 1973, the company expects to be generating about 40 per cent of its power with nuclear facilities.

Chicago Daily News
3/9/70

Nuclear power for Chicago: our first unit works so well we're building you five more.

DEFENDANT'S EXHIBIT 96

Dresden One was our pioneer. Sure, it helped make a brighter Chicago. More important, it showed that nuclear-powered generating units are more efficient and reliable. And, by using nuclear energy we could produce electricity at about ten percent less cost.

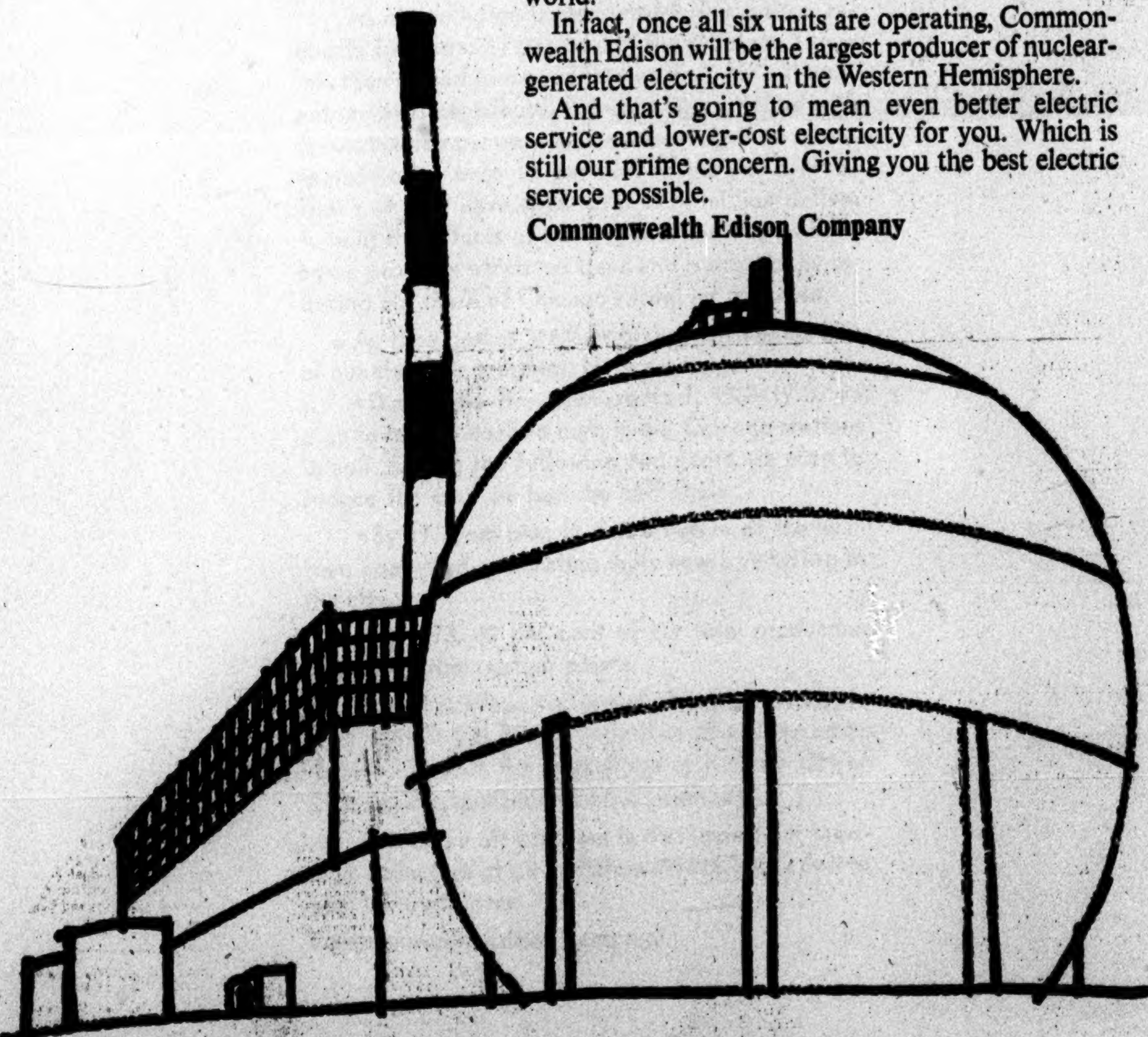
Result?

By the early 1970s we plan to add five more nuclear units. Each to be one of the largest in the world.

In fact, once all six units are operating, Commonwealth Edison will be the largest producer of nuclear-generated electricity in the Western Hemisphere.

And that's going to mean even better electric service and lower-cost electricity for you. Which is still our prime concern. Giving you the best electric service possible.

Commonwealth Edison Company



The bright new ideas are Electric.

CHICAGO DAILY NEWS, Monday, March 13, 1967

DEFENDANT'S EXHIBIT 97

First Report

Commonwealth Edison Reports on Chicago's Air Pollution Problem

We share the concern of all Chicagoans for clean air. Edison's future depends on Chicago, just as Chicago depends on Edison for electricity.

As air pollution is measured today, Edison accounts for under 11 per cent of the problem. This is less than it used to be and far less than, for instance, automobiles contribute. But we're not satisfied with favorable comparisons and we don't want to be responsible for even 11 per cent of the pollution. That's why we have spent over fifty million dollars to limit the effects of burning coal and why we have had a program which has been and is drastically reducing our share of Chicago's total air pollution.

As time passes, we'll be giving you the features of our clean air program. Here's a start:

• During the five-year period, 1968-1973, we plan to cut the coal we burn in our Chicago stations in half. During the following two years, we plan to reduce the coal we burn by half again.

• By 1973, we plan to retire twelve of the nineteen coal-fired generating units now operating in the city.

• By 1973, 40 per cent of our total production will come from nuclear plants.

• We'll continue to be well ahead of the objectives established for the reduction of sulfur emissions set forth in the original schedule of the City of Chicago's air pollution control ordinance.

Our clean air program is designed for maximum reduction of air pollution at reasonable cost to you, our customers.

Commonwealth Edison Company

DEFENDANT'S EXHIBIT 98

Commonwealth Edison Reports on Progress Toward Cleaner Air

In January 1967, Commonwealth Edison Company submitted a report to the City of Chicago outlining plans for an accelerated program of air pollution reduction consistent with maintaining power reliability throughout the Chicago area. We promised to do our share to clean up the air while continuing to meet our important responsibility of providing power whenever and wherever it's needed throughout our 13,000-square-mile service area. Here's how we're living up to our responsibilities:

We're burning less coal

The fastest way we can cut down our share of Chicago's air pollution is to burn less coal. We're following this plan and meeting our targets ahead of schedule. In 1968 we cut the coal-burn at our four Chicago stations by nearly 15 percent. By 1973 we'll be burning 50 percent less coal in Chicago than we did in 1967. This means there will be half the smoke coming out of our stacks—half the sulfur dioxide, half of all emissions. And by 1975, we'll cut our coal-burn in half again.

More furnace retirements

Since 1956, we have retired 14 coal-fired units from our four Chicago plants. Twelve more units will be retired in the near future. By the end of 1971 only seven will be in operation. The coal-burning units are being replaced by fast-start peaking units that use gas or low sulfur oil, by extra-high-voltage power lines that bring power into Chicago from distant generating stations, and by clean nuclear energy.

Use of natural gas increased

Our generating stations are using natural gas in greater quantities. This year, gas burned at our plants in and near the city will replace nearly 1,700,000 tons of coal. A great deal of this gas, along with low sulfur oil, is fueling the fast start-up generators we've installed in our plants during the past two years. It cost $110 million to install these units. They will help solve the air pollution problem, while improving the dependability of our power supply.

More nuclear power

Clean, combustion-free production of electricity is a specialty of nuclear power plants. Dresden, our first nuclear station, has produced over 8¼ billion kilowatt-hours of electricity for our customers since it went into operation in 1960. Now we're spending $900 million for six additional nuclear units and fuel to raise our nuclear capacity above 5 million kilowatts by the end of 1973. In that year, nuclear generation will account for 40 percent of the electricity required by our customers.

These are the main points of our clean air program. In the near future, we'll be telling you about additional aspects. We hope you'll agree that we are doing our share to give Chicago clean air.

Commonwealth Edison Company

DEFENDANT'S EXHIBIT 99

A Public Service Memorandum from Commonwealth Edison

No smoke. No dirt. No fumes.

In the foreground [illegible] Dresden Number Two, which will open this Spring.

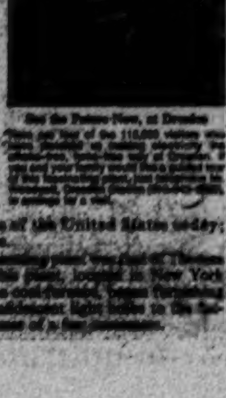
How Commonwealth Edison pioneered the production of electricity from a vast new source of energy which does not pollute the air you breathe

It all began on an abandoned squash court under the stands of Stagg Field at the University of Chicago.

There, on December 2, 1942, a team of scientists under the direction of Dr. Enrico Fermi achieved the first nuclear chain reaction. It was the power of the universe brought under man's control.

A new age began that day. Mankind had discovered how to use a new source of energy, with limits not yet known, to augment the non-renewable supplies of coal, oil, and natural gas buried in the earth millions of years ago and being used up at an enormously increasing rate.

For nuclear power comes from the heart of the atom. It can be made into useful energy anywhere that a nuclear reactor can be built and operated. Unlike the burning of coal, oil, and gas, nuclear reactions produce no smoke, no dirt, no fumes to pollute the air.



See the Future-Now, at Dresden

[illegible]

Clean, silent nuclear energy can be transformed into clean, silent electricity, at costs which permit its use in most parts of the United States today; eventually, everywhere.

The first electric generating plant was that of Thomas A. Edison. In 1882 this plant, located in New York City and powered by a coal-fired [illegible], began furnishing electricity for 800 incandescent light bulbs to the factories, offices, and homes of a few [illegible].

From that time on, as new uses for electricity were found and the demand for it increased, power had been supplied by the burning of coal, oil, or gas, or by water power.

Although Dr. Fermi may not have thought of his achievement in those terms, it was as though thousands of Niagaras, Hoover Dams, and Grand Coulees suddenly had been put down on the face of the earth.

Again it was in the Chicago area that the commercial use of privately-financed nuclear energy first became a reality: at Commonwealth Edison's 200,000-kilowatt Dresden Nuclear Power Station, 50 miles southwest of Chicago.

It was designed and constructed under the close supervision of the Atomic Energy Commission which, on May 4, 1956, issued a construction permit.

Dresden went on full power June 29, 1960.

Since then, 13 other nuclear plants have been put into operation by other electrical companies in this country. But Commonwealth Edison, the pioneer, remains the leader. Our nuclear program is the largest of any private utility in the United States, both in terms of dollars invested and kilowatts of capacity.

From the time a company decides to build a nuclear plant until the plant begins to produce electricity, at least five years pass. That's if all the contractors meet their delivery dates. It's safer to plan on seven years.

Pollution-Preventing Pellets

[illegible]

We now have six new, large, nuclear generating stations under construction.

Dresden Number Two will be in operation this Spring.

Dresden Number Three is scheduled to go on line next Winter.

Each of these new Dresden units has more than four times the capacity of Dresden Number One.

Yet this is only one long stride in our nuclear program.

Four more nuclear units are being built.

Quad-Cities, on the Mississippi River near Rock Island, Illinois, will have two units like the new ones at Dresden. The first is scheduled to open in 1971, the second in 1972.

At Zion, Illinois, on Lake Michigan a few miles south of the Wisconsin state line, our sixth and seventh nuclear units are under construction. One will open in 1972, the other in 1973.

Well within the next four years, our total capacity of the nuclear stations will be 5,200,000 kilowatts, 26 times what it is today. That is far more electricity than the entire city of Chicago now uses.

By that time, Commonwealth Edison will have spent nearly one billion dollars to develop nuclear power, to keep pace with your growing demand for electricity without emitting the slightest trace of smoke, sulfur dioxide, or dust.

We have spent and are spending millions more for the most modern dust-collecting precipitators, for gas turbines, and for the conversion of coal-burning units to other fuels.

Commonwealth Edison's total activities to reduce and prevent air pollution add up to the greatest single effort to clear the air which we know of today.

Commonwealth Edison Company

A Public Service Memorandum from Commonwealth Edison

You're looking at 20,000 tons of smokeless, fumeless "coal."

This is a picture of a nuclear fuel "bundle."

It's 14 feet long, 5½ inches square.

It holds 49 fuel rods, each made up of pellets of nuclear fuel so small (and so safe) you could hold a dozen or more in your hand.

It will produce as much electricity as 20,000 tons of coal, without putting the slightest trace of smoke or sulfur dioxide into the air.

In a month or so, it will be making power for you at Commonwealth Edison's new nuclear power unit, Dresden Number Two, 50 miles southwest of Chicago.

Since June, 1960, we have operated the world's first privately-financed nuclear power station, Dresden Number One, designed and constructed under the close supervision of the Atomic Energy Commission.

Scientists from the U.S. Public Health Service recently made a complete review of Dresden One and its effect on its surroundings. They checked air, rain, snow, soil, corn, grass, milk, cattle, fish, and river water. They found no harmful effects, after ten years of operation.

Commonwealth Edison has the largest program of any electric company in the nation for the production of nuclear power.

Inside this "containment vessel" is the nuclear reactor for Commonwealth Edison's third smoke-free, fume-free power station: Dresden Number Three, scheduled [illegible] nuclear power plants next winter. The protruding pipes will carry [illegible] in the first two Dresden [illegible]es, steam, air and water to and from the vessel's interior.

We have five more new, large, nuclear generating units under construction.

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Quad-Cities, on the Mississippi River near Cordova, Illinois, will have two units. The first is scheduled to open in 1971, the second in 1972.

At Zion, Illinois, on Lake Michigan a few miles south of the Wisconsin state line, our sixth and seventh nuclear units are being built. One will open in 1972, the other in 1973.

Well within the next four years, the total capacity of our nuclear stations will be 5,200,000 kilowatts, 26 times what it is today. That is far more electricity than the entire city of Chicago now uses.

By then, we will have spent nearly one billion dollars to develop nuclear power, to keep pace with your growing demand for electricity without emitting pollutants.

We have spent and are spending millions more for the most modern dust-collecting precipitators, for gas turbines, and for the conversion of coal-burning units to other fuels.

Commonwealth Edison's total activities to reduce and prevent air pollution add up to the greatest single effort we know of to clean the air.

Commonwealth Edison Company

DEFENDANT'S EXHIBIT 101

DRAFT — N O T F O R P U B L I C A T I O N

COAL STRIP MINING - IS IT REACHING A PEAK?

by

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For about half a century, strip mining has been providing an ever-increasing share of total coal output in the United States, and in the past 30 years this share has grown from less than 8 percent to 33.7 percent, as shown in Figure 1. The graph also shows that strip mining is gaining faster in the West than in the East.

From 1961 to 1967, output from strip mines grew 63.6 million tons, or 52.2 percent. Certainly there is nothing in such performance to indicate any peaking in the level of strip coal-mine production. But the fact is that, if not in actual tonnage, strip mining appears to be reaching its peak in relative importance, at least east of the Mississippi River. And the area east of the Mississippi provides 90.0 percent of the strip and 94.9 percent of the total coal production of the nation.

The relative economic advantage which spurred strip mining's growth for a third of a century has been diminishing markedly in recent years. Figure 2 shows evidence of this decline. From 1947 until 1961, strip tonnage output remained fairly stable, at the end of the period showing only a 12.5 percent decline. Meanwhile, underground coal production fell 44.5 percent. As the result of the greater decline in underground coal, strip coal in 1961 furnished 30.3 percent of the total coal produced, compared to only 22.1 percent in 1947.

In the succeeding 6 years, however, underground coal output increased by 76.5 million tons, while strip output increased only 63.6 million.

Further evidence of the strengthening of underground coal's relative position - or if you will, the weakening of strip coal's position - can be found in the major coal stripping states, Illinois, West Kentucky, Ohio, Pennsylvania, Indiana, and West Virginia, which in 1966 provided 80 percent of the nation's strip coal. Figure 3 shows what has been happening in three states lying in the Appalachian field and in the total output of these three states. In the figure, the column height represents the output of coal mined by all methods. The number at the base of each column is the percentage mined by stripping.

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In Pennsylvania and Ohio, the percentage of strip mining increased between 1956 and 1961, but by 1966 had declined from the 1961 level. In West Virginia a decline occurred during the first 5 years but was followed by a rise.

In January 1968, Coal Age published an article listing the locations and capacities of new large mines in the planning and construction stages that would be operating by 1968-1971.

The plans for West Virginia and Pennsylvania indicated all the new mines would be underground. Except to the extent they might replace existing underground capacity, the new mines will increase the dominance of underground coal. Announced capacity for Ohio is 24.7 percent strip, which is much below the present level.

Figure 4 shows similar data for Illinois, West Kentucky, and Indiana individually and combined. The percentage of strip mining grew for each of the 5-year periods in Illinois and West Kentucky. During the second 5-year period, however, the increase was considerably less. In these states the projected new capacity should also exert a downward pressure.

Alone among the states illustrated, Indiana shows a strong tendency toward an increase in the relative position of strip mining.

If strip mining actually is destined to provide a smaller share of total coal output, as the evidence indicates, the cause must lie in a diminution of the economic advantage that strip mining has enjoyed in the past. The narrowing of this advantage appears to be taking place in a number of ways.

PRODUCTIVITY OF WORKMEN

From the beginning, the output per man day, or as it is more commonly stated, manshift, in strip mining has been well above that in underground mining. Figure 5 shows the increasing spread in tons per manshift in strip and underground mining. In 1943 the figures were 15.46 tons per man day for strip mining compared to 5.04 for underground mining. With the improvement of methods and equipment during the succeeding two decades, the output per manshift by 1966 had risen to 33.6 tons for strip and 14.6 tons for underground mining.

Despite the increasing spread in average productivities, the difference in labor costs per ton between the two methods has been diminishing. The reciprocal of tons per manshift, or the fraction of a manshift per ton, provides better comparison of cost, for it is a measure of the time spent on a unit of output. Man days per ton are shown in Figure 6. Also shown is the decline in the margin of advantage held by strip mining. Whereas in 1956 it took an average of .069 of a shift more labor to produce a ton by underground mining than by strip mining, in 1966 the difference was only .039 of a shift. If, for example, we assume an average wage of $28.00 per shift for both types

of mining, then stripping's margin of labor advantage would have been reduced from $1.93 to $1.09. More accurate comparisons of changes over a period of time must, of course, consider changes in wage rates and different wage rates for different types of labor.

Figure 7 shows changes in the margins for five important strip mining states. In all areas, the margin has been shrinking. The size of the margin in labor costs is, of course, only one of the things that govern whether strip or underground mining will be used. Many other factors, both physical and economic, are involved.

OVERBURDEN AND STRIPPING EQUIPMENT

As strip mining has progressed, the average depth of overburden and the ratio of overburden to coal have been gradually increasing (Figure 8). The reported average depth of overburden for coal strip mines in the United States increased from 31.6 feet in 1946 to 41.6 in 1955 and to 50.1 in 1965. Cubic yards of overburden per ton of coal increased from 9.1 cubic yards in 1946 to 12.3 in 1955 and to 12.8 in 1965.

Figure 8 shows changes in the thickness of both overburden and coal in strip mines of the major producing areas. The thickness of coal mined has, in general, remained relatively stable, and in some states the reported average ratio of overburden to coal has shown no major change. In all states, however, the average depth has changed significantly. Not shown on Figure 8 is the increase in maximum depth, which in some states now exceeds 100 feet.

The use of larger equipment has enabled coal strippers to handle the thicker overburden economically, either by using larger single units or units working in tandem. Since the mid-1950s, shovel capacities have increased from about 65 cubic yards to 115 cubic yards in 1959 and to 180 cubic yards in 1966, with still larger shovels scheduled soon. Draglines have shown a similar growth in size. While such equipment is physically capable of moving deeper and deeper overburden, the performance increase is not always proportional to the investment cost. For example, a 100-cubic yard shovel operating at a depth of 92 feet can handle somewhat more than twice the volume of a 45-cubic yard shovel operating in 52 feet of overburden. But operating under these conditions for the same thickness of coal, net increase in coal availability would be less than 20 percent. Since the purchase price of the larger shovel will be two to three times that of the smaller, shovel investment and depreciation per ton of coal, as well as shovel operating costs, are greatly increased. Thus, the margin of cost, or the advantage of stripping over underground mining, tends to narrow with the depletion of shallow reserves and increase in overburden thickness.

RESERVE REQUIREMENTS AND COSTS

During the 32 years from 1935 through 1966, the cumulative total of coal strip mined in the United States was almost 3.5 billion tons. Even if it were assumed strip mining were to show no annual tonnage gain and remain at its 1966 level, the next 3.5 billion tons would require only slightly more than 18 years to produce.

U. S. Bureau of Mines figures show that the average thickness of coal mined by strip mining in 1965 was 5.2 feet. Calculations based on this thickness indicate that the mining of 3.5 billion tons would require the uncovering of 466 thousand acres of coal, assuming coal in the ground at 1800 tons per acre-feet and 80 percent recovery.

The problem of future reserves of strip coal will not be as much one of scarcity as of availability. Studies by the Illinois State Geological Survey indicate that in Illinois alone the coal lying under overburden of 100 feet or less thick amounts to more than 3 times 3.5 billion tons. The problem, east of the Mississippi, at least, will be one of piecing together coal and surface rights to make a block sufficiently large for an economical operation.

Large outputs over a long period of years are required to justify and amortize the investments in equipment for handling thick overburden. In 1965 the outputs of the 10 largest strip mines in the United States ranged from 2.2 to 3.8 million tons. Twenty-five years' output would be 55 to 95 million tons. In 6-foot coal at 80 percent recovery, 4770 to 8246 acres would be required. In 4-foot coal the acreages would be increased 50 percent. For most economic mining, each acreage should preferably be in a single block to avoid the moving of giant equipment. Coal stripping companies, unless they already possess the required reserves, will face increasing difficulty in piecing together blocks of such size.

RECLAMATION

Progressive strip mining operators have engaged in stripped land reclamation for many years. In recent years, however, states in increasing numbers have been passing new and more stringent laws governing the type and degree of reclamation or restoration that must be attained. The cost per acre reclaimed for any required degree of reclamation depends on many things, among which are the depth of overburden, the type of stripping equipment that has been used, and the chemical and structural character of the overburden material.

Reported reclamation costs for acreages of coal lands reclaimed in 1964 ranged from less than 100 dollars per acre for partial reclamation of one small area to almost 1000 dollars per acre for another area. The overall average for partial reclamation of 11,185 acres was 149 dollars per acre. Average cost for completely reclaiming 21,541 acres was reported at 230 dollars per acre.[1/]

Figure 9 shows the cost per ton of coal for various thicknesses of coal at an assumed cost per acre reclaimed.

That increased requirements for reclamation will bring increased costs for strip mining has been recognized by TVA and that agency's contracts for coal are based on prices that cover these costs.

LAND ACQUISITION COSTS

There has been a steady rise in land and real estate prices in recent decades. U. S. Department of Agriculture indexes of the average value of farm land and buildings show the following changes:

	Index 1957-1959 = 100		Percent increase
	1960	1968	1960-1968
U. S.	111	170	53.2
Illinois	106	156	47.2
Indiana	107	165	54.2
Kentucky	112	175	56.3
Ohio	105	153	45.7
Pennsylvania	111	171	54.1
West Virginia	110	150	36.3

The average total increase for the United States in the 8-year period was 53.2 percent. The increase varied considerably from place to place. For individual states shown, it ranged from 36.3 percent in West Virginia to 56.3 percent in Kentucky. However small or great the increase, wherever surface rights must be acquired land price trends are one more factor diminishing the economic advantage that strip mining possesses.

Figure 9 can be used to estimate the effects of inflation in land costs. If, for example, the land cost in an area where coal averaged 4 feet thick were to increase from 400 dollars per acre to 600 dollars per acre, the cost per ton of coal would increase 3.48 cents.

SUMMARY

For half a century the percentage of coal production provided through strip mining has steadily increased. Recent trends indicate that a peak in percentage, if not in tonnage, is being approached. Important among the reasons for this is the decline in economic advantage enjoyed by strip mining compared to underground mining. Among the factors contributing to this decline are the following:

1. Decrease in the margin of advantage in manpower requirements held by strip mining.

2. Increase in depth and volume of overburden necessitating larger equipment and investment of more capital.

3. Increasing scarcity of reserve blocks of land big enough to support extensive mining operations.

4. Increasingly stringent legislation for reclamation of stripped land and the resulting higher cost of reclamation.

5. Increasing cost of land surface rights..

1/ Surface Mining and Our Environment, U. S. Department of the Interior, 1967, Appendix I, Table 5.

In the eastern part of the United States there has already been a peaking and decline in the relative importance of strip mining in some major coal producing states. Although it is not clear at what point the pressures discussed above will cause a peaking for the region as a whole, the trends indicate that this definitely is on the way.

In the less populated states of the West, some of the pressures are less severe. This is especially true of those pressures related to conflicting or competitive land uses that affect the availability of reserves and cost of land. The other pressures, although they may not become sufficiently strong to cause a decline in western strip mining's relative importance, will, nevertheless, reduce to an increasing degree the advantage that strip mining has possessed.

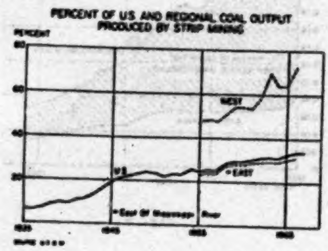

Fig. 1

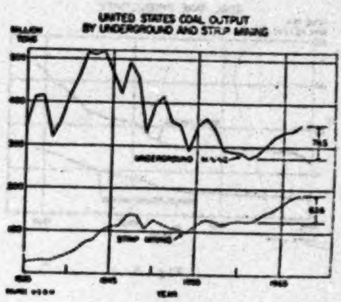

Fig. 2

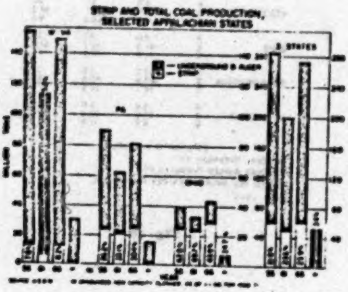

Fig. 3

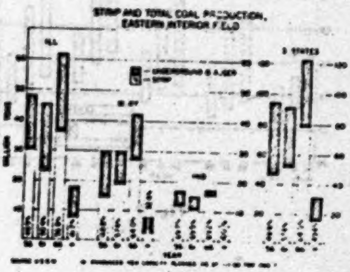

Fig. 4

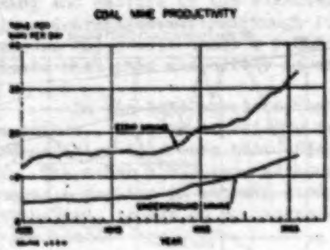

Fig. 5

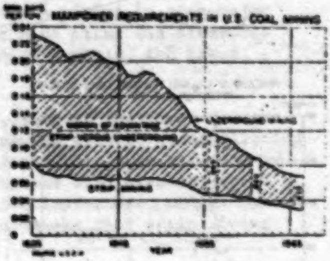

Fig. 6

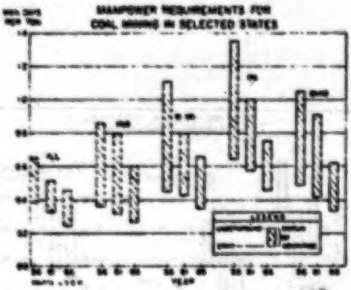

Fig. 7

STRIPPING DATA, AVERAGES, FOR SELECTED AREAS

AREA	ITEM	YEAR 1953	1955	1958
ILLINOIS	A	4.8	5.0	5.3
	B	62.7	61.9	69.6
	C	12.8	13.2	13.6
INDIANA	A	4.4	4.8	4.2
	B	43.2	46.0	49.0
	C	14.9	13.4	16.4
KENTUCKY	A	5.0	5.1	5.0
	B	57.6	46.1	54.3
	C	9.9	9.2	9.4
OHIO	A	3.8	3.7	3.6
	B	41.2	46.7	50.5
	C	14.6	14.8	14.3
PENNSYLVANIA	A	3.2	3.2	3.2
	B	45.5	43.5	48.4
	C	14.1	14.6	17.6
W. VIRGINIA	A	5.0	4.9	4.9
	B	57.0	48.2	61.2
	C	9.9	11.8	11.3

EXPLANATION OF ITEM

A = COAL THICKNESS, FT

B = OVERBURDEN THICKNESS, FT

C = CU YDS OVERBURDEN PER TON OF COAL

Fig. 8

ESTIMATED COST OF LAND RECLAMATION

COAL THICKNESS IN FEET	ASSUMED COST PER ACRE $200	$300	$400	$500	$600	$700	$800
	COST IN CENTS PER TON *						
2	6.94	10.42	13.89	17.36	20.83	24.31	27.78
4	3.47	5.21	6.94	8.68	10.42	12.15	13.89
6	2.31	3.47	4.63	5.79	6.94	8.10	9.26
8	1.71	2.56	3.41	4.27	5.12	5.97	6.83

* BASED ON 1800 TONS PER ACRE-FOOT OF COAL IN PLACE, WITH 80% RECOVERY

Fig. 9